LINN ENERGY, LLC
Form 10-K
February 29, 2008

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, 2007

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 Street, 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 Stock Market LLC

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 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 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. (Check one):

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 $1,974,449,832 on June 29, 2007, based on $32.91 per unit, the last reported sales price of the units on The NASDAQ Global Market on such date.

As of January 31, 2008, there were 114,632,034 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 May 29, 2008.

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GLOSSARY OF TERMS

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

ARO. Asset retirement obligation.

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 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 to 59.5 degrees Fahrenheit.

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

Dth. One decatherm, equivalent to one million British thermal units.

Developed acres. Acres spaced or assigned to productive wells.

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.

FERC. Federal Energy Regulatory Commission.

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

LIBOR. London Interbank Offered Rate.

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

Mcf. One thousand cubic feet.

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

MMBtu. One million British thermal units.

MMcf. One million cubic feet.

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

MMcfe/d. One 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.

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

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

PEPL. Panhandle Eastern Pipeline.

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. Additional oil and gas 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. Proved oil and gas reserves are the estimated quantities of gas, natural gas liquids and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions. The definition of proved reserves is in accordance with the Securities and Exchange Commission s definition set forth in Regulation S-X Rule 4-10(a) and its subsequent staff interpretations and guidance.

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 drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. 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 tests in the area and in the same reservoir.

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 oil and/or gas 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 therefrom. 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.

SEC. Securities and Exchange Commission.

Standardized Measure. Standardized Measure, or standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities, is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the Securities and Exchange Commission (using prices and costs in effect as of the date of estimation) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%. The Company s Standardized Measure does not include future income tax expenses because the reserves are owned by its subsidiaries, which are not subject to income taxes.

Successful well. A well capable of producing oil, gas and/or NGL in commercial quantities.

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 and gas regardless of whether such acreage contains proved reserves.

Unproved resources. Resources that are considered less certain to be recovered than proved reserves. Unproved resources may be further sub-classified to denote progressively increasing uncertainty of recoverability.

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.

Part I

Item 1. Business and Properties

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 Properties 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 Part II. Item 8. Financial Statements and Supplementary Data.

Overview

Linn Energy is an independent oil and gas company focused on the development and acquisition of long life properties which complement its asset profile in producing basins within the United States. Linn Energy began operations in March 2003 and completed its initial public offering (IPO) in January 2006.

The Company s oil, gas and NGL properties are currently located in three regions in the United States:

- Mid-Continent, which includes the core operating areas Texas Panhandle and Oklahoma;
- Appalachian Basin, which includes fields in West Virginia and Pennsylvania; and
- Western, which includes the Brea Olinda Field of the Los Angeles Basin in California.

Proved reserves at December 31, 2007 were 1,616.1 Bcfe, of which approximately 64% were gas, 20% were oil and 16% were NGL. Approximately 73% were classified as proved developed, with a total Standardized Measure value of $3.46 billion. At December 31, 2007, the

Company operated 5,638, or 77%, of its 7,305 gross productive wells. Average proved reserves-to-production ratio, or average reserve life, is approximately 22 years, based on the December 31, 2007 reserve report and annualized production for the fourth quarter ended December 31, 2007.

In January 2008, the Company completed two acquisitions of oil and gas properties in the Mid-Continent and Appalachian Basin regions. See Recent Developments below for additional details about these acquisitions. On a pro forma basis, including these two acquisitions, total proved reserves at December 31, 2007 were 1,945.5 Bcfe, of which approximately 55% were gas, 32% were oil and 13% were NGL.

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 that support this goal:

- acquire long life, high quality properties;
- efficiently operate and develop acquired properties; and
- capture cash flow margin through commodity price and interest rate hedging.

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

Item 1. Business and Properties - Continued

Strategy

Acquire Long Life, High Quality Properties

The Company s acquisition program targets oil and gas properties which offer high quality, long life production with predictable decline curves as well as lower-risk development opportunities. The Company evaluates acquisitions based on reserve base, decline curve, reserve life, field cash flow and costs of development and operations.

The following provides a summary of acquisitions of working and royalty interests the Company has completed from inception through the date of this report:

Year	# of Acquisitions	Gross Wells (1)	Operating Region	Aggregate Contract Price (in millions)
2003	4	498	Appalachian Basin	$ 52.0
2004	2	698	Appalachian Basin	25.9
2005	3	718	Appalachian Basin	124.5
2006	5	1,430	Mid-Continent, Appalachian Basin and Western	451.7
2007	8	4,505	Mid-Continent, Appalachian Basin and Western	2,678.9
2008	2	2,450	Mid-Continent and Appalachian Basin	566.9
	24	10,299		$ 3,899.9

(1) Gross wells do not include approximately 1,800 wells associated with royalty interest acquisitions.

From inception through the date of this report, the Company has completed 24 acquisitions of working and royalty interests in oil and gas properties and related gathering and pipeline assets. Total acquired proved reserves were approximately 1.9 Tcfe at an acquisition cost of approximately $2.11 per Mcfe. See Note 2 for additional details about the Company s acquisitions.

The Company finances acquisitions with a combination of proceeds from the issuance of its units, bank borrowings and cash flow from operations. During 2007, the Company completed three private placements of its units, with gross proceeds of $2.12 billion. During 2006, the Company completed one additional private placement, with gross proceeds of $305.0 million. See Recent Developments below and also Note 4 for additional details about the Company s private placement of units.

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 Company s development program is focused on lower-risk, repeatable drilling opportunities to maintain and/or grow long-term cash flow. Many of the Company s wells are completed in multiple producing zones with commingled production and long economic lives. The number, types and location of wells the Company drills vary depending on its capital budget, the cost of each well, anticipated production and the estimated recoverable reserves attributable to each well. In addition, the Company seeks to deliver attractive financial returns by leveraging its purchasing power, experienced workforce and scalable infrastructure. For 2008, the Company estimates its total drilling and development capital expenditures will be between $250.0 million and $300.0 million. This estimate is under continuous review and is subject to on-going adjustment.

Item 1. Business and Properties - Continued

Capture Cash Flow Margin Through Commodity Price and Interest Rate Hedging

The Company has derivative contracts in place covering a significant portion of its forecasted production volumes through 2012, or five years, to capture cash flow margins and provide long-term cash flow predictability to pay distributions and manage its business. Currently, the Company utilizes swaps and puts to hedge oil and gas production and oil puts to hedge NGL production. Swap contracts establish a fixed price and put options set a price floor with the potential for realized commodity price upside beyond the hedge price floor. For 2008, the Company s production is approximately 97% hedged. As of February 22, 2008, puts represent 25%, 27%, 36%, 40% and 16% of annual hedged volume for all commodities for the each of the years ended December 31, 2008 through December 31, 2012.

In addition, the Company enters into interest rate hedges to minimize the effects of fluctuations in interest rates. Currently, the Company utilizes LIBOR swaps to convert its borrowing rate on indebtedness under its credit facility from a floating to fixed rate. As of February 1, 2008, the Company has swapped LIBOR on approximately 61% of its outstanding debt at a fixed rate of 4.20% for 2008 and 5.06% for 2009 and 2010. For additional details about the Company s interest rate swap agreements and commodity derivative contracts, see Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation and Item 7A. Quantitative and Qualitative Disclosures About Market Risk. See also Note 8 and Note 9.

Recent Developments

Acquisitions

On January 31, 2008, the Company completed the acquisition of certain oil and gas properties, effective October 1, 2007, located primarily in the Mid-Continent region from Lamamco Drilling Company for a contract price of $552.2 million, subject to purchase price adjustments. The acquired reserves are approximately 88% oil and over 70% proved developed with a low base decline rate of approximately 5% and a reserve life index of over 34 years. This acquisition provides a large inventory of approximately 800 development projects which the Company anticipates will create future organic growth opportunities. The acquisition was financed with a combination of borrowings under the Company s credit facility and proceeds from a term loan entered into at closing. See Note 2 for additional details.

On January 4, 2008, the Company completed the acquisition of certain gas properties, effective November 1, 2007, located in the Appalachian Basin from K V Oil and Gas, Inc. for contract consideration of 600,000 units (approximately $14.7 million), subject to purchase price adjustments.

Distributions

In January 2008, the Company s Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2007. The distribution totaled approximately $72.2 million and was paid on February 14, 2008 to unitholders of record as of the close of business on

February 8, 2008. This distribution represents a 10.5% increase in the Company s annualized cash distribution rate, to $2.52 per unit, from $2.28 per unit for the third quarter of 2007.

Item 1. Business and Properties - Continued

Private Placements

During 2007 and 2006, the Company closed four private placements of units to groups of institutional investors.

Date Issued	Gross Proceeds		Units Issued	Date Converted to Units (1)	Date Registered With SEC	Date Lock-Up Expired (2)
	(in thousands)					
August 2007:						
Units	$	416,000	12,999,989		December 2007	February 14, 2008
D Units		1,084,000	34,997,005	November 2007	December 2007	February 14, 2008
	$	1,500,000	47,996,994			
June 2007:						
Units	$	260,000	7,761,194		December 2007	February 14, 2008
February 2007:						
Units	$	172,904	6,650,144		December 2007	December 14, 2007
C Units		187,096	7,465,946	April 2007	December 2007	December 14, 2007
	$	360,000	14,116,090			
October 2006:						
Units	$	116,228	5,534,687		December 2007	December 14, 2007
B Units		188,772	9,185,965	January 2007	December 2007	December 14, 2007
	$	305,000	14,720,652			

(1) Not applicable for units.

(2) Lock-up expiration date represents date investors were allowed to sell or transfer units per terms of purchase agreements.

The proceeds from the private placements, net of expenses, were used to finance acquisitions and to repay indebtedness under the Company s credit facility. See Note 4 for additional details about the private placements.

Operating Regions

Mid-Continent

The Mid-Continent is the Company s largest region, and as noted above, includes two key core operating areas. First, the Texas Panhandle area, which consists of shallow oil and gas production from the Brown Dolomite formation at depths of approximately 3,200 feet and the Deep Granite Wash formation which produces at depths ranging from 8,900 feet to 16,000 feet. The second core area is located primarily in Oklahoma. Producing depths range from 6,000 feet to 20,000 feet in this area.

Texas Panhandle proved reserves represented approximately 33%, of total proved reserves at December 31, 2007, of which 53% were proved developed reserves. This area produced 71.6 MMcfe/d, or 36%, of the Company s fourth quarter 2007 production. During 2007, the Company invested approximately $104.0 million to drill in the Texas Panhandle. During 2008, the Company anticipates spending 60% to 65% of its total capital budget for development activities in this area.

The Oklahoma proved reserves represented approximately 41%, of total proved reserves at December 31, 2007, of which 83% were proved developed reserves. This area produced 92.7 MMcfe/d, or 46%, of the Company s fourth quarter 2007 production. During 2007, the Company invested approximately $40.0 million to drill in Oklahoma. During 2008, the Company anticipates spending 25% to 30% of its total capital budget for development activities in this area.

In order to more efficiently transport its gas to market, the Company owns and operates a network of gas gathering systems comprised of approximately 800 miles of pipeline and associated compression and metering facilities which connect to numerous sales outlets in the Texas Panhandle.

Item 1. Business and Properties - Continued

Appalachian Basin

The Appalachian Basin includes fields in West Virginia and Pennsylvania. Appalachian Basin proved reserves represented approximately 12%, of total proved reserves at December 31, 2007, of which 75% were proved developed reserves. This region produced 24.3 MMcfe/d, or 12%, of the Company s fourth quarter 2007 production. During 2007, the Company invested approximately $34.3 million to drill in the Appalachian Basin. During 2008, the Company anticipates spending 10% to 12% of its total capital budget for development activities in the Appalachian Basin region.

The proximity of the Company s properties in this region to major United States consuming markets allows the Company to receive premium pricing on this production. In order to more efficiently transport its gas to market, the Company owns and operates a network of gas gathering systems comprised of approximately 1,000 miles of pipeline and associated compression and metering facilities which connect to numerous sales outlets on seven interstate and six intrastate pipelines in the Appalachian Basin. During 2007, the Company invested approximately $17.2 million to expand its network of pipeline in this region.

The Company also performs limited gas gathering activities for others on non-jurisdictional gathering systems, primarily in Pennsylvania. The Company aggregates these volumes with production and sells all the gas through meters to the same purchasers. These revenues are collected and distributed to the third party producers in the normal course of business.

Western

Western consists of the Brea Olinda Field of the Los Angeles Basin in California. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation. Western proved reserves represented approximately 14%, of total proved reserves at December 31, 2007, of which 86% were proved developed reserves. This region produced 11.6 MMcfe/d, or 6%, of the Company s fourth quarter 2007 production. During 2007, the Company invested approximately $2.4 million to drill in this region. During 2008, the Company anticipates spending less than 5% of its total capital budget for development activities in the Western region.

The Western region also includes the operation of a gas processing facility which processes produced gas from Company and third party wells. Processed gas is utilized to generate electricity which is used in the field to power equipment, resulting in reduced operating costs. Revenues are also generated from the sale of excess power and associated NGL.

Drilling and Acreage

The following sets forth the wells drilled during the periods indicated (gross refers to the total wells in which the Company had a working interest and net refers to gross wells multiplied by its working interest):

	Year Ended December 31,		
	2007	2006	2005
Gross wells:			
Productive	247	154	110
Non-productive	6	5	
Total	253	159	110
Net development wells:			
Productive	213	147	105
Non-productive	6	5	
Total	219	152	105
Net exploratory wells:			
Productive			
Non-productive			
Total			

The totals above do not include 25 lateral segments added to existing vertical wellbores in the Texas Panhandle core operating area. All of the non-productive wells in 2007 were due to mechanical failures. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation

Item 1. Business and Properties - Continued

between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of oil, gas or NGL, regardless of whether they generate a reasonable rate of return. At December 31, 2007, the Company had 10 (9 net) wells in process.

The following sets forth information, as of December 31, 2007, relating to the Company s drilling locations and net acres of leasehold interests in its three operating regions at that date:

	Mid-Continent (1)	Appalachian Basin	Western	Total (2)
Proved undeveloped	852	404	2	1,258
Other locations	2,359	1,076	6	3,441
Total drilling locations	3,211	1,480	8	4,699
Leasehold interests-net acres	765,488	182,186	3,961	951,635

(1) Does not include approximately 800 proved and other locations acquired in January 2008 with the Company s acquisition of properties from Lamamco. See Recent Developments above.

(2) Does not include optimization projects.

As shown in the table above, as of December 31, 2007, the Company had 1,258 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 3,441 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, 2007. 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 do not include approximately 1,800 productive wells in which the Company owns a royalty interest only.

	Gas Wells		Oil Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Operated (1)	4,133	3,421	1,505	1,406	5,638	4,827

Non-operated (2)	1,413	231	254	27	1,667	258
Total (3)	5,546	3,652	1,759	1,433	7,305	5,085

(1) 10 operated wells had multiple completions at December 31, 2007.

(2) 3 non-operated wells had multiple completions at December 31, 2007.

(3) Does not include approximately 2,450 gross wells acquired in January 2008. See Recent Developments above.

Item 1. Business and Properties - Continued

Developed and Undeveloped Acreage

The following sets forth information as of December 31, 2007, relating to leasehold acreage:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Operated	968,486	604,391	356,793	215,288	1,325,279	819,679
Non-operated	641,397	100,506	57,456	31,450	698,853	131,956
Total	1,609,883	704,897	414,249	246,738	2,024,132	951,635

Production, Price and Cost History

The Company s gas production is primarily sold under market sensitive price contracts, which typically sell at differentials to the NYMEX or PEPL gas prices due to the Btu content and the proximity to major consuming markets. The Company s 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 gas and NGL recovered after transportation and processing of gas. These purchasers sell the residual gas and NGL based primarily on spot market prices. Under percentage-of-index contracts, the price per MMBtu the Company receives for gas is tied to indexes published in *Gas Daily* or *Inside FERC Gas Market Report.* Although exact percentages vary daily, as of December 31, 2007, approximately 85% of the Company s gas production was sold under short-term contracts at market-sensitive or spot prices. The remainder was sold under long-term contracts.

The Company s oil and NGL production is primarily sold under market sensitive percentage-of-index contracts and percentage-of-proceeds contracts and as of December 31, 2007, approximately 60% of its oil production and 95% of its NGL production was sold under long-term contracts.

As discussed in the Strategy section above, the Company enters into derivative transactions in the form of hedging arrangements to reduce the impact of commodity price volatility on its cash flow from operations. By removing price volatility from a significant portion of its production, the Company has mitigated, but not eliminated, potential effects of fluctuating oil, gas and NGL prices on its cash flow from operations for those periods.

Item 1. Business and Properties - Continued

The following sets forth information regarding net production of oil, gas and NGL and certain price information for each of the periods indicated:

	Year Ended December 31,		
	2007	2006	2005
Production:			
Gas production (MMcf)	27,001	8,599	4,720
Oil production (MBbls)	1,271	370	20
NGL production (MBbls)	992		
Total production (MMcfe)	40,579	10,818	4,839
Average daily production (MMcfe/d)	111.2	29.6	13.3
Weighted average prices (hedged): (1)			
Gas (Mcf)	$ 8.19	$ 9.79	$ 6.45
Oil (Bbl) (2)	$ 66.15	$ 58.68	$ 52.55
NGL (Bbl)	$ 56.75	$	$
Total (Mcfe)	$ 8.91	$ 9.79	$ 6.51
Weighted average prices (unhedged): (3)			
Gas (Mcf)	$ 6.62	$ 7.17	$ 9.24
Oil (Bbl) (2)	$ 66.51	$ 50.68	$ 52.55
NGL (Bbl)	$ 55.51	$	$
Total (Mcfe)	$ 7.84	$ 7.43	$ 9.23
Average unit costs per Mcfe of production:			
Operating expenses	$ 2.18	$ 1.67	$ 1.52
General and administrative expenses (4)	$ 1.41	$ 3.70	$ 0.69
Depreciation, depletion and amortization	$ 2.41	$ 2.23	$ 1.51

(1) Includes the effect of realized gains on derivatives of $43.2 million and $25.5 million and realized losses of $13.1 million for the years ended December 31, 2007, 2006 and 2005, respectively.

(2) Oil production in California is sold pursuant to a long-term contract at 79% of NYMEX, and with gravity increase due to NGL being mixed into the oil stream, prices realized average approximately 82% of NYMEX.

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

(4) The measure for the years ended December 31, 2007 and 2006 includes approximately $13.9 million and $21.6 million of unit-based compensation and unit warrant expense, respectively. The measure for the year ended December 31, 2006 includes $2.0 million of IPO bonuses paid to certain executive officers. General and administrative expenses excluding these amounts were $1.07 per Mcfe and $1.51 per Mcfe for the years ended December 31, 2007 and 2006, respectively. This is a non-GAAP measure used by Company management to analyze its performance.

Item 1. Business and Properties - Continued

Reserve Data

Proved Reserves

Proved oil and gas reserves are the estimated quantities of oil, gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements, but not escalations based on future conditions. For additional information regarding estimates of oil, gas and NGL reserves, including estimates of proved and proved developed reserves, the standardized measure of discounted future cash flows and the changes in discounted future cash flows, see Supplemental Oil and Gas Data (Unaudited) in Item 8. Financial Statements and Supplementary Data.

The following presents estimated net proved oil, gas and NGL reserves and the present value of estimated proved reserves at December 31, 2007, 2006 and 2005, based on reserve reports prepared by independent engineers DeGolyer and MacNaughton at December 31, 2007 and 2006 and a reserve report prepared by independent engineers Schlumberger Data and Consulting Services at December 31, 2005. The Standardized Measure values shown are not intended to represent the market value of estimated oil, gas and NGL reserves at such dates.

	December 31,		
	2007	**2006**	**2005**
Reserve data: **(1)**			
Estimated net proved reserves:			
Gas (Bcf)	1,028.9	274.0	191.9
Oil (MMBbls)	54.8	30.0	0.2
NGL (MMBbls)	43.1		
Total (Bcfe)	1,616.1	454.1	193.2
Proved developed (Bcfe)	1,172.1	314.1	125.2
Proved undeveloped (Bcfe)	444.0	140.0	68.0
Proved developed reserves as a % of total proved reserves	72.5 %	69.2 %	64.8 %
Standardized measure (in millions) **(2)**	$ 3,458.2	$ 552.3	$ 552.1
Representative oil and gas prices at period end:			
Gas NYMEX per MMBtu	$ 6.80	$ 5.64	$ 10.08
Oil NYMEX West Texas Intermediate per Bbl	$ 95.92	$ 61.05	$ 57.98

(1) Excludes reserves of approximately 329.4 Bcfe based on internal Company estimates for the January 2008 acquisitions discussed in Recent Developments above.

(2) Does not give effect to derivative contracts. For additional details about the Company s derivative contracts, see Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation and Item 7A. Quantitative and Qualitative Disclosures About Market Risk. See also Note 8 and Note 9.

The data in the above table are estimates. Oil and gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and gas 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 and gas that are ultimately recovered.

These reserve estimates are reviewed and approved by Company senior engineering staff and management, with final approval by its Chief Operating Officer. 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. The independent engineering firms 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. In the conduct of their preparation of the reserve estimates, the independent engineering firms did not independently verify the accuracy and completeness of information and data furnished by the Company with respect to ownership interests, oil and gas 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 which 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. Their estimates of reserves conform to the guidelines of the SEC, including the criteria of reasonable certainty, as it pertains to expectations

Item 1. Business and Properties - Continued

about the recoverability of reserves in future years, under existing economic and operating conditions. The Company has not filed reserve estimates with any Federal authority or agency, with the exception of the SEC, since the last fiscal year ended.

Future prices received for production may vary, perhaps significantly, from the prices assumed for purposes of the estimate of Standardized Measure. The Standardized Measure shown should not be construed as the market value of the reserves at the dates shown. The 10% discount factor required to be used pursuant to Statements of Financial Accounting Standards (SFAS) No. 69, *Disclosures about Oil and Gas Producing Activities,* 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 the Company or the oil and gas industry. The Standardized Measure, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Oil, Gas and NGL Sales - 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, 2007, sales of oil, gas and NGL to Duke Energy Corporation, Dominion Resources, Inc. and ConocoPhillips accounted for approximately 21%, 20% and 12%, respectively, of the Company s total volumes, or 53% in the aggregate. If the Company were to lose any one of its major oil and gas purchasers, the loss could temporarily cease or delay production and sale of its oil and 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 gas purchasers ceased purchasing oil and gas altogether, it could have a detrimental effect on the oil and gas market in general and on the volume of oil and gas that it is able to sell.

Competition

The oil and 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 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 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.

In addition, 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.

Item 1. Business and Properties - Continued

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 cannot predict the continued availability of insurance or the availability of insurance at premium levels that justify its purchase. The Company has elected to self-insure for trucks and vehicles licensed to operate on public highways and roads. The Company may elect to self-insure for additional items if it is 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.

The Company participates in a substantial percentage of wells on a non-operated basis, and may be accordingly limited in its ability to control the risks associated with oil, gas and NGL operations.

Title to Properties

Prior to the commencement of drilling operations, the Company conducts a thorough 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 gas 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 oil and gas properties and believes that it has satisfactory title to its producing properties in accordance with standards generally accepted in the oil and gas industry. Oil and 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 certain regions of the United States that the Company operates in (primarily in parts of the Appalachian Basin and the Mid-Continent). These seasonal anomalies can pose challenges for meeting the well drilling objectives and increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations.

The demand for gas typically decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, certain gas users utilize gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand fluctuations. The demand for crude oil is generally determined at a global level, based on supply shortage concerns driven primarily by natural disasters such as hurricanes and by political instability in certain oil producing regions of the world.

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 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.

Item 1. Business and Properties - Continued

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas 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 clean-up requirements for the oil and 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 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 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
- U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

In addition, the Kyoto Protocol to the United Nations Framework Convention on Climate Change (Kyoto Protocol) requires Annex I countries, including Canada and the United Kingdom, to reduce their emissions of carbon dioxide and other greenhouse gases. As a result of the ratification of the Kyoto Protocol and the adoption of legislation or other regulatory initiatives designed to implement its objectives by the national and regional governments, reductions in greenhouse gases from crude oil and natural gas producers may be required which could result in, among other things, increased operating and capital expenditures for those producers. Until such legislation or other regulatory initiatives are finalized, the impact of the Kyoto Protocol and any such legislation adopted as a result of its ratification remains uncertain.

Various states regulate the drilling for, and the production, gathering and sale of, oil and gas, 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 oil and gas resources. States may regulate rates of production and may establish maximum daily production allowables from gas wells based 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, 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 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. However, the Company cannot predict how future environmental laws and regulations may impact its properties or operations. For the year ended December 31, 2007, 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 2008 or that will otherwise have a material impact on its financial position or results of operations.

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Item 1. Business and Properties - Continued

Executive Officers of the Company

Name	Age	Position with the Company
Michael C. Linn	56	Chairman and Chief Executive Officer
Mark E. Ellis	52	President and Chief Operating Officer
Kolja Rockov	37	Executive Vice President and Chief Financial Officer
Lisa D. Anderson	47	Senior Vice President and Chief Accounting Officer
Charlene A. Ripley	44	Senior Vice President, General Counsel and Corporate Secretary
Arden L. Walker, Jr.	48	Senior Vice President - Operations and Chief Engineer

Michael C. Linn is the Chairman and Chief Executive Officer of the Company and has served in such capacity since December 2007. Prior to that, from June 2006 to December 2007, Mr. Linn served as Chairman, President and Chief Executive Officer and from March 2003 to June 2006, he was the President, Chief Executive Officer and Director. From 2000 to 2003 Mr. Linn was President of Allegheny Interests, Inc., a private oil and gas investment company. From 1980 to 1999, Mr. Linn served as General Counsel (1980-1982), Vice President (1982-1987), President (1987-1990) and CEO (1990-1999) of Meridian Exploration, a private Appalachian Basin oil and gas company that was sold to Columbia Natural Gas Company in 1999. Both Allegheny Interests and Meridian Exploration were wholly owned by Mr. Linn and his family. Mr. Linn is the immediate past Chairman of the Independent Petroleum Association of America, the largest national trade association of independent oil and gas producers. He currently sits on the Boards of the National Petroleum Council and the American Exploration and Production Council and is a member of the oil and gas industry s 25 Year Club. He was recently appointed as a Texas representative to the Legal and Regulatory Affairs Committee of the Interstate Oil and Gas Compact Commission. He is also Chairman of the Houston Wildcatters Committee of the Texas Alliance of Energy Producers. Mr. Linn regularly appears on behalf of the industry before state and federal agencies, such as the Department of Energy, Department of the Treasury, Federal Energy Regulatory Commission and the Environmental Protection Agency. In addition, he has testified on behalf of the industry before various committees and subcommittees of the U.S. House of Representatives and the U.S. Senate and is regularly quoted and has published various articles for trade publications and newspapers. He is also a frequent guest on radio and television programs representing the industry. His civic affiliations include memberships on the Boards of Small Steps and the Youth Development Center, in addition to memberships on the American Art Committee of the Museum of Fine Arts Houston and the Corporate Committee of Texas Children s Hospital.

Mark E. Ellis is the President and Chief Operating Officer and has served in such capacity since December 2007. From December 2006 to December 2007, Mr. Ellis was the Executive Vice President and Chief Operating Officer of the Company. Mr. Ellis has over 28 years of experience in the oil and 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 and a past board member of the New Mexico Oil & Gas Association, 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, 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 over 15 years of experience in the oil and 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 U.S. exploration and production sector. From September 2000 until October 2004, Mr. Rockov was a Director at RBC Capital Markets. Prior to September 2000, Mr. Rockov held various senior positions with Dain Rauscher Wessels and Rauscher Pierce Refsnes, Inc., predecessors of RBC Capital Markets.

Item 1. Business and Properties - Continued

Lisa D. Anderson has been the Senior Vice President and Chief Accounting Officer since July 2006. Ms. Anderson oversees the Company s accounting, financial reporting, information technology, treasury, tax and internal control functions. Her career spans over 25 years of financial accounting and consulting experience and includes previous leadership positions with international risk consulting firms and as an audit partner with a major international accounting firm, where she specialized in the oil and gas industry. Before joining the Company, she was the Managing Director leading the Financial Reporting Risk Services practice for Protiviti from November 2005 until July 2006. She served as a Managing Director with Jefferson Wells from January 2002 to August 2005. Prior to 2002, she was an Assurance Partner with KPMG LLP. Ms. Anderson is a Certified Public Accountant and a Certified Internal Auditor. She is a member of the American Institute of Certified Public Accountants, Texas Society of CPAs and the Institute of Internal Auditors. In addition, she has served on the Presidential Advisory and the Educational Curriculum Committees of the Texas Society of Certified Public Accountants and currently serves on the Board of the Greater Houston Convention and Visitors Bureau.

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, Vice President and General Counsel from 2003 to 2004 and Vice President, General Counsel and Secretary of Anadarko Canada Corporation and its predecessor companies since 1998. She served as Senior Counsel for Norcen Energy Resources Limited from 1997 to 1998.

Arden L. Walker, Jr. is the Senior Vice President - Operations and Chief Engineer of the Company. Mr. Walker joined the Company in February 2007 to oversee its Western operations, which includes California, Oklahoma and Texas. 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. From January 2002 until June 2004, Mr. Walker served as Business Development Manager 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.

Item 1. Business and Properties - Continued

Employees

As of December 31, 2007, the Company employed approximately 525 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 Street, Suite 5100, Houston, Texas 77002. The main telephone number is (281) 840-4000.

Company Website

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

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

Forward-Looking Statements

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

- business strategy;
- acquisition strategy;
- financial strategy;
- drilling locations;
- oil, gas and NGL reserves;

- realized oil, gas and NGL prices;
- production volumes;
- lease operating expenses, general and administrative expenses and finding 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 Part I. Item 1. Business and Properties; Part I. Item 1A. Risk Factors; Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation 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, intend, anticipate, believe, estimate, predict, potential, pursue, target, continue, the negative of such terms or other comparable te

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

Item 1. Business and Properties - Continued

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.

Securities Act Disclaimer

This Form 10-K does not constitute an offer to sell or the solicitation of an offer to buy any securities.

Item 1A. Risk Factors

Our business has many risks. Factors that could materially adversely affect our business, financial condition, 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.

Risks Related to Our Business

We may not have sufficient cash flow from operations to pay the quarterly distribution at the current distribution level 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, gas and NGL;
- prices at which oil, 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; 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.

We actively seek to acquire oil and gas properties. Acquisitions involve potential risks that could adversely impact our future growth and our ability to increase or pay distributions.

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;
- 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;

Item 1A. Risk Factors - Continued

- 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 and term loan. These facilities have substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations and our ability to pay distributions to our unitholders.

We have significant indebtedness under our credit facility and term loan. As of January 31, 2008, we had an aggregate of approximately $1.99 billion outstanding under our credit facility and term loan (with additional borrowing capacity of approximately $314.5 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 amount of our indebtedness may also cause us to be more vulnerable to economic downturns and adverse developments in our business. Our ability to access the capital markets to raise capital on favorable terms will be affected by our debt level and by adverse market conditions resulting from, among other things, general economic conditions, contingencies and uncertainties that are difficult to predict and impossible to control. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness.

We depend on these facilities for future capital needs and to fund our distributions. The credit facility and term loan restrict our ability to obtain additional financing, make investments, lease equipment, sell assets 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 a default, which could cause all of our existing indebtedness to be immediately due and payable.

As noted above, we depend on our credit facility for future capital needs. In addition, we have drawn on our credit facility to fund or partially fund quarterly cash distribution payments, since we use operating cash flows for investing activities and borrow as cash is needed. Absent such borrowing, we would have at times experienced a shortfall in cash available to pay our declared quarterly cash distribution amount. If there is a default under our credit facility, we would be unable to make borrowings to fund distributions.

Availability under our credit facility is determined semi-annually at the discretion of the lenders and is based in part on oil, gas and NGL prices. 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.

Item 1A. Risk Factors - Continued

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, 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.

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 hedging 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, gas and NGL, we enter into hedging arrangements for a significant portion of our production. 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 hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction of our liquidity.

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.

Our revenue, profitability and cash flow depend upon the prices of and demand for oil, gas and NGL. The oil, 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, 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, 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 gas producing countries, including those in the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain price and production controls;
- the impact of the U.S. dollar exchange rates on oil, 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, 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.

Item 1A. Risk Factors - Continued

Future price declines or downward reserve revisions may result in a write-down of our asset carrying values.

Declines in oil, 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 non-cash charge to earnings, the carrying value of our properties for impairments. 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, 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, gas and NGL reserves and production and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing and exploiting 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, gas and NGL in an exact way. Reserve engineering requires subjective estimates of underground accumulations of oil, gas and NGL and assumptions concerning future oil, 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, 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, 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, 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, gas and NGL reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of estimate. However, actual future net cash flows from our oil and gas properties also will be affected by factors such as:

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

Item 1A. Risk Factors - Continued

In addition, the 10% discount factor, required to be used pursuant to Statement of Accounting Standard No. 69 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 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 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, 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, gas and NGL we are able to produce from existing wells;
- the prices at which we are able to sell our oil, 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, 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, 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, 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 condition or results of operations.

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, 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 condition 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, gas and NGL we produce, and could reduce our cash available for distribution and adversely impact expected increases in oil, gas and NGL production from our drilling program.

The marketability of our oil, gas and NGL production depends in part on the availability, proximity and capacity of gathering and pipeline systems. The amount of oil, 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

Item 1A. Risk Factors - Continued

additional production. As a result, we may not be able to sell the oil, 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, gas and NGL we produce, and could reduce our cash available for distribution and adversely impact expected increases in oil and gas production from our drilling program.

We depend on certain key customers for sales of our oil, 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 non-payment could have an adverse impact on our financial condition and results of operations.

For the year ended December 31, 2007, Duke Energy Corporation, Dominion Resources, Inc. and ConocoPhillips accounted for approximately 21%, 20% and 12%, respectively, of our total volumes, or 53% in the aggregate. For the year ended December 31, 2006, Dominion Resources, Inc. and ConocoPhillips accounted for approximately 53%, and 14%, respectively, of our total volumes, or 67% in the aggregate. To the extent these and other customers reduce the volumes of oil, 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, 2007, we had identified 4,699 drilling locations, of which 1,258 were proved undeveloped locations and 3,441 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, gas and NGL prices, costs and drilling results. In addition, DeGolyer and MacNaughton has not estimated proved reserves for the 3,441 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, 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, gas and NGL are high risk activities with many uncertainties that could adversely affect our financial condition 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, 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, particularly seasonal weather conditions in the spring;
- facility or equipment malfunctions;

Item 1A. Risk Factors - Continued

- title problems;
- pipeline ruptures or spills;
- compliance with environmental and other governmental requirements;
- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- formations with abnormal pressures;
- fires;
- blowouts, craterings and explosions; and
- uncontrollable flows of oil, 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 condition and results of operations.

Because we handle oil, 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. We may not be able to recover these costs from insurance. For a more

Item 1A. Risk Factors - Continued

detailed discussion of environmental and regulatory matters impacting our business, see Part I. Item 1. Business and Properties - 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 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, 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 Part I. Item 1. Business and Properties - Environmental Matters and Regulation.

As of December 31, 2007, we concluded that our disclosure controls and procedures were effective. If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results could be harmed. We cannot be certain that our efforts to maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002. For additional information, see Part II. Item 9A. Controls and Procedures in this Annual Report on Form 10-K for the year ended December 31, 2007.

Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet certain reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our units.

Item 1A. Risk Factors - Continued

Risks Related to Our Structure

Our management may have conflicts of interest with the untiholders. 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 non-affiliated 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 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 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%, and would likely pay state income tax at varying rates. 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. 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, beginning in 2008, we will be required to pay Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of such a tax on us by Texas and, if applicable, by any other state, will reduce the cash available for distribution to our unitholders.

Item 1A. Risk Factors - Continued

Our unitholders may have more complex tax reporting and may be required to pay taxes on income even if they do not receive any cash distributions from us.

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. Furthermore, distributions to unitholders in excess of the total net taxable income they were allocated, decreases their tax basis, which will become ordinary taxable income to them if the unit is later sold at a price greater than their tax basis, even if the price received is less than their original cost.

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 2007, we have done business and owned assets in West Virginia, Pennsylvania, New York, Virginia, California, Oklahoma, Kansas, New Mexico, Illinois, Indiana, 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. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our units.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

The Company s obligations under its credit facility are secured by mortgages on its oil and gas properties. See Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation and Note 7 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, Kansas, Oklahoma, Pennsylvania, Texas and West Virginia.

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

A special meeting of Company unitholders was held on November 1, 2007. The matters voted on at the meeting and the results are set forth below.

1. To vote upon (a) a change in terms of the Company s Class D units to provide that each Class D unit converts automatically into a unit and (b) the issuance of 34,997,005 units upon such conversion.

Votes For	Votes Against or Withheld	Abstentions
48,064,105	106,238	49,018

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 31, 2008, there were approximately 411 unitholders of record.

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

Quarter	Unit Price Range High		Unit Price Range Low		Cash Distribution Declared PerUnit	
2007:						
October 1 - December 31	$	30.79	$	22.88	$	0.57
July 1 - September 30	$	37.80	$	31.64	$	0.57
April 1 - June 30	$	39.61	$	32.47	$	0.52
January 1 - March 31	$	35.05	$	30.16	$	0.52
2006:						
October 1 - December 31	$	33.46	$	21.21	$	0.43
July 1 - September 30	$	24.10	$	20.08	$	0.40
April 1 - June 30	$	21.00	$	18.72	$	0.32
January 13 - March 31	$	22.35	$	19.55	$	

Distributions

The Company s limited liability company agreement requires it to make quarterly distributions to untiholders 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);

- 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 Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation - Liquidity and Capital Resources for a discussion on the payment of future distributions.

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 day 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, 2007
Linn Energy, LLC	$100	$128(1)
Alerian MLP Index	$100	$136
S&P 500 Index	$100	$118

(1) Based on the last reported sale price of the Company s units as reported by NASDAQ on December 31, 2007 ($25.03).

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 Form 10-K or future filings with 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 Part III. Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters regarding securities authorized for issuance under the Company s equity compensation plans, which information is incorporated by reference into this Item 5.

Sales of Unregistered Securities

None not previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K. See Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation for discussion of these matters.

Item 6. Selected Financial Data

The selected financial data set forth below should be read in conjunction with Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation 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.

	Year Ended December 31, 2007	2006	2005	2004	Period from March 14, 2003 (Inception) - December 31, 2003
	(dollars and units in thousands)				
Statement of operations data:					
Oil, gas and NGL sales	$ 318,226	$ 80,393	$ 44,645	$ 19,502	$ 2,379
Gain (loss) on oil and gas derivatives (1)	(345,537)	103,308	(76,193)	(11,004)	(1,437)
Total revenues	(7,237)	191,058	(26,481)	9,178	946
Operating income (loss)	(266,743)	103,931	(48,864)	(1,204)	(1,197)
Depreciation, depletion and amortization	97,964	24,173	7,294	3,656	562
Interest expense	62,130	25,857	8,043	3,530	517
Net income (loss)	(364,349)	79,185	(56,351)	(4,816)	(1,688)
Net income (loss) per unit basic	(5.29)	2.64	(2.75)	(0.23)	(0.06)
Net income (loss) per unit diluted	(5.29)	2.61	(2.75)	(0.23)	(0.06)
Distributions declared per unit	2.18	1.15			
Weighted average units outstanding	68,916	28,281	20,518	20,518	27,813
Cash flow data:					
Net cash provided by (used in):					
Operating activities (2)	$ (44,814)	$ (6,805)	$ (29,518)	$ 10,351	$ (135)
Investing activities	(2,892,420)	(551,631)	(150,898)	(61,373)	(35,344)
Financing activities	2,932,080	553,990	189,269	31,167	57,521
Capital expenditures	2,896,958	551,737	150,849	63,594	32,863
Balance sheet data:					
Total assets	$ 3,796,569	$ 905,912	$ 280,924	$ 105,425	$ 79,177
Long-term debt	1,443,830	428,237	207,695	72,750	41,518
Unitholders capital (deficit)	2,026,641	450,954	(46,831)	9,520	14,336
Operating data:					
Production:					
Gas (MMcf)	27,001	8,599	4,720	3,110	304
Oil (MBbls)	1,271	370	20	10	31
NGL (MBbls)	992				
Total (MMcfe)	40,579	10,818	4,839	3,112	492
Average daily production (MMcfe/d)	111.2	29.6	13.3	8.5	2.3
Estimated Net Proved Reserves:					
Gas (Bcf)	1,028.9	274.0	191.9	118.9	68.9
Oil (MMBbls)	54.8	30.0	0.2	0.1	0.2
NGL (MBbls)	43.1				

Total (Bcfe)		1,616.1		454.1		193.2		119.8		69.8
Total Weighted Average Prices:										
Hedged (Mcfe) (3)	$	8.91	$	9.79	$	6.51	$	5.55	$	5.17
Unhedged (Mcfe) (3)	$	7.84	$	7.43	$	9.23	$	6.27	$	4.84

(1) During 2005, the Company canceled (before their original settlement date) a portion of out-of-the-money gas swaps and realized a loss of $38.3 million. The Company subsequently hedged similar volumes at higher prices. The remaining 2005 loss relates to losses on derivative positions settled in 2005 at scheduled maturity dates that were not related to the cancellation of out-of-the-money gas hedges.

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

(3) Hedged amounts include the effect of realized gains and losses on derivatives and unhedged amounts do not.

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

The following discussion and analysis should be read in conjunction with the Selected Historical Consolidated Financial and Operating Data and the financial statements and related notes included elsewhere in this Annual Report on Form 10-K. 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, gas and NGL, production volumes, estimates of proved reserves, capital expenditures, economic and competitive 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 Part I. 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 Summary

Linn Energy is an independent oil and gas company focused on the development and acquisition of long life properties which complement its asset profile in producing basins within the United States.

Proved reserves at December 31, 2007 were 1,616.1 Bcfe, of which approximately 64% were gas, 20% were oil and 16% were NGL. Approximately 73% were classified as proved developed, with a total Standardized Measure value of $3.46 billion. At December 31, 2007, the Company operated 5,638, or 77%, of its 7,305 gross productive wells. Average proved reserves-to-production ratio, or average reserve life, is approximately 22 years, based on the December 31, 2007 reserve report and annualized production for the fourth quarter ended December 31, 2007.

During the year ended December 31, 2007, the Company completed eight acquisitions of working and royalty interests in oil and gas properties. In January 2008, the Company completed two additional acquisitions of oil and gas properties. On a pro forma basis, including these two acquisitions, total proved reserves at December 31, 2007 were 1,945.5 Bcfe, of which approximately 55% were gas, 32% were oil and 13% were NGL.

Acquisitions

The following provides a summary of acquisitions of working and royalty interests the Company has completed from January 1, 2007 through the date of this report:

Date	Gross Wells (1)	Operating Region		Aggregate Contract Price (in millions)
January 2007	51	Appalachian Basin	$	33.0
February 2007	4	Appalachian Basin		5.9
February 2007	851	Mid-Continent		415.0
April 2007	300	Western		10.0
June 2007	514	Mid-Continent		90.5
August 2007	2,685	Mid-Continent		2,050.0
October 2007	100	Mid-Continent		22.5
October 2007		Mid-Continent		52.0
January 2008	2,312	Mid-Continent		552.2
January 2008	138	Appalachian Basin		14.7
	6,955		$	3,245.8

(1) Gross wells do not include approximately 1,800 wells associated with royalty interest acquisitions.

From inception through the date of this report, the Company has completed 24 acquisitions of working and royalty interests in oil and gas properties and related gathering and pipeline assets. Total acquired proved

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Continued

reserves were approximately 1.9 Tcfe at an acquisition cost of approximately $2.11 per Mcfe. See Note 2 for additional details about the Company s acquisitions.

The Company finances acquisitions with a combination of proceeds from the issuance of its units, bank borrowings and cash flow from operations. During 2007, the Company completed three private placements of its units, with gross proceeds of $2.12 billion. During 2006, the Company completed one additional private placement, with gross proceeds of $305.0 million. See Private Placements below and also Note 4 for additional details about the Company s private placement of units.

Private Placements

During 2007 and 2006, the Company closed four private placements of units to groups of institutional investors.

Date Issued	Gross Proceeds		Units Issued	Date Converted to Units (1)	Date Registered With SEC	Date Lock-Up Expired (2)
	(in thousands)					
August 2007:						
Units	$	416,000	12,999,989		December 2007	February 14, 2008
D Units		1,084,000	34,997,005	November 2007	December 2007	February 14, 2008
	$	1,500,000	47,996,994			
June 2007:						
Units	$	260,000	7,761,194		December 2007	February 14, 2008
February 2007:						
Units	$	172,904	6,650,144		December 2007	December 14, 2007
C Units		187,096	7,465,946	April 2007	December 2007	December 14, 2007
	$	360,000	14,116,090			
October 2006:						
Units	$	116,228	5,534,687		December 2007	December 14, 2007
B Units		188,772	9,185,965	January 2007	December 2007	December 14, 2007
	$	305,000	14,720,652			

(1) Not applicable for units.

(2) Lock-up expiration date represents date investors were allowed to sell or transfer units per terms of purchase agreements.

The proceeds from the private placements, net of expenses, were used to finance acquisitions and to repay indebtedness under the Company s credit facility. See Note 4 for additional details about the private placements.

Operating Regions

The Company s oil, gas and NGL properties are currently located in three regions in the United States:

- Mid-Continent, which includes the core operating areas Texas Panhandle and Oklahoma;
- Appalachian Basin, which includes fields in West Virginia and Pennsylvania; and
- Western, which includes the Brea Olinda Field of the Los Angeles Basin in California.

Mid-Continent

The Mid-Continent is the Company s largest region, and as noted above, includes two key core operating areas. First, the Texas Panhandle area, which consists of shallow oil and gas production from the Brown Dolomite formation at depths of approximately 3,200 feet and the Deep Granite Wash formation which produces at depths ranging from 8,900 feet to 16,000 feet. This area produced 71.6 MMcfe/d, or 36%, of the Company s fourth quarter 2007 production. *The second core area is located primarily in Oklahoma. Producing depths range from 6,000 feet*

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Continued

to 20,000 feet in this area. This area produced 92.7 MMcfe/d, or 46%, of the Company s fourth quarter 2007 production. During 2007, the Company invested approximately $40.0 million to drill in Oklahoma.

In order to more efficiently transport its gas to market, the Company owns and operates a network of gas gathering systems comprised of approximately 800 miles of pipeline and associated compression and metering facilities which connect to numerous sales outlets in the Texas Panhandle.

Appalachian Basin

The Appalachian Basin includes fields in West Virginia and Pennsylvania. This region produced 24.3 MMcfe/d, or 12%, of the Company s fourth quarter 2007 production. During 2007, the Company invested approximately $34.3 million to drill in the Appalachian Basin. The proximity of the Company s properties in this region to major United States consuming markets allows the Company to receive premium pricing on this production.

The Company also performs limited gas gathering activities for others on non-jurisdictional gathering systems, primarily in Pennsylvania. The Company aggregates these volumes with production and sells all the gas through meters to the same purchasers. These revenues are collected and distributed to the third party producers in the normal course of business.

Western

Western consists of the Brea Olinda Field of the Los Angeles Basin in California. The Brea Olinda Field was discovered in 1880 and produces from the shallow Pliocene formation to the deeper Miocene formation. This region produced 11.6 MMcfe/d, or 6%, of the Company s fourth quarter 2007 production. During 2007, the Company invested approximately $2.4 million to drill in this region.

The Western region also includes the operation of a gas processing facility which processes produced gas from Company and third party wells. Processed gas is utilized to generate electricity which is used in the field to power equipment, resulting in reduced operating costs. Revenues are also generated from the sale of excess power.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Continued

Results of Operations - Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

The following provides selected financial and operating data for the years indicated:

	Year Ended December 31, 2007	Year Ended December 31, 2006 (in thousands)	Variance
Revenues:			
Gas sales	$ 178,627	$ 61,641	$ 116,986
Oil sales	84,538	18,752	65,786
NGL sales	55,061		55,061
Total oil, gas and NGL sales	318,226	80,393	237,833
Gain (loss) on oil and gas derivatives	(345,537)	103,308	(448,845)
Natural gas marketing revenues	15,537	5,598	9,939
Other revenues	4,537	1,759	2,778
Total revenues	$ (7,237)	$ 191,058	$ (198,295)
Expenses:			
Operating expenses	$ 88,527	$ 18,099	$ 70,428
Natural gas marketing expenses	12,596	4,862	7,734
General and administrative expenses	57,188	39,993	17,195
Data license expenses	3,231		3,231
Depreciation, depletion and amortization	97,964	24,173	73,791
Total expenses	$ 259,506	$ 87,127	$ 172,379
Other income and (expenses)	$ (94,033)	$ (28,148)	$ (65,885)

	Year Ended December 31, 2007	Year Ended December 31, 2006	Variance
Production:			
Gas production (MMcf)	27,001	8,599	214.0%
Oil production (MBbls)	1,271	370	243.5%
NGL production (MBbls)	992		
Total production (MMcfe)	40,579	10,818	275.1%
Average daily production (MMcfe/d)	111.2	29.6	275.7%
Weighted average prices (hedged): (1)			
Gas (Mcf)	$ 8.19	$ 9.79	(16.3)%
Oil (Bbl) (2)	$ 66.15	$ 58.68	12.7%
NGL (Bbl)	$ 56.75	$	
Weighted average prices (unhedged): (3)			
Gas (Mcf)	$ 6.62	$ 7.17	(7.7)%
Oil (Bbl) (2)	$ 66.51	$ 50.68	31.2%
NGL (Bbl)	$ 55.51	$	
Average unit costs per Mcfe of production:			
Operating expenses	$ 2.18	$ 1.67	30.5%
General and administrative expenses (4)	$ 1.41	$ 3.70	(61.9)%

Depreciation, depletion and amortization	$	2.41	$	2.23	8.1%

(1) Includes the effect of realized gains of $43.2 million and $25.5 million on derivatives for the years ended December 31, 2007 and 2006, respectively.

(2) Oil production in California is sold pursuant to a long-term contract at 79% of NYMEX, and with gravity increase due to NGL being mixed into the oil stream, prices realized average approximately 82% of NYMEX.

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

(4) The measure for the years ended December 31, 2007 and 2006 includes approximately $13.9 million and $21.6 million, respectively, of unit-based compensation and unit warrant expense. The year ended December 31, 2006 also includes approximately $2.0 million of IPO bonuses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2007 and 2006 were $1.07 per Mcfe and $1.51 per Mcfe, respectively. This is a non-GAAP measure used by Company management to analyze its performance.

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

Revenues

Gas, oil and NGL sales increased 296%, to approximately $318.2 million for the year ended December 31, 2007, from $80.4 million for the year ended December 31, 2006.

The increase in revenue from gas, oil and NGL sales was primarily attributable to increased production as a result of acquisitions and drilling. Total production increased to 40,579 MMcfe during the year ended December 31, 2007, from 10,818 MMcfe during the year ended December 31, 2006. The increase in production was due primarily to production from oil and gas properties acquired during 2007 and 2006 and by the drilling of new wells. The Company drilled 253 wells during 2007, compared to 159 wells during 2006.

Gas production increased to 27,001 MMcf during the year ended December 31, 2007, from 8,599 MMcf during the year ended December 31, 2006, with the 2007 acquisitions in the Mid-Continent region (see Note 2) contributing approximately 15,734 MMcf from the respective closing dates of the acquisitions. The increase in production was slightly offset by a reduction in the weighted average gas price, from $7.17 per Mcf during the year ended December 31, 2006, to $6.62 per Mcf during the year ended December 31, 2007, which caused gas revenues to decrease approximately $4.8 million.

Oil production increased to 1,271 MBbls during the year ended December 31, 2007, from 370 MBbls during the year ended December 31, 2006, due to the acquisitions in the Western and Mid-Continent regions. The acquisitions in the Mid-Continent also increased NGL production to 992 MBbls during the year ended December 31, 2007, from zero during the comparative period of the prior year. The increase in the weighted average price of oil for the period, from $50.68 per Bbl to $66.51 per Bbl, contributed approximately $5.9 million to the increase in oil revenues.

Hedging Activities

During the year ended December 31, 2007, the Company had commodity pricing derivative contracts for approximately 82% of its gas production and 86% of its oil and NGL production, which resulted in realized gains of $43.2 million (greater revenues than would have been achieved at unhedged prices). During the year ended December 31, 2006, the Company had approximately 108% of its gas production and 50% of its oil production hedged, which resulted in realized gains of $25.5 million. Unrealized losses on derivatives in the amount of $388.7 million for the year ended December 31, 2007, and unrealized gains of $77.8 million for the year ended December 31, 2006, were also recorded. Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract price on the derivative. During 2007, expected future oil and gas prices increased, which reduced the market value of the derivatives. Such market value adjustment, if realized in the future, would be offset by higher actual prices for production. Since the Company has hedged a significant portion of its oil and gas production at fixed prices, it may not realize the benefit of future increases in commodity prices. However, the Company utilizes put contracts as a significant percentage of its hedging portfolio. Puts not only protect against declines in commodity prices, but also preserve commodity upside. See Note 9 for details regarding derivatives in place through December 31, 2013.

Expenses

Operating expenses, which include expenses such as lease operating, labor, field office, vehicle, supervision, transportation, maintenance, tools, supplies, and production and ad valorem taxes, increased to $88.5 million for the year ended December 31, 2007, from $18.1 million for the year ended December 31, 2006. Production taxes, which are a function of volumes and revenues generated from production, increased to $17.8 million for the year ended December 31, 2007, from $2.0 million in 2006. Ad valorem taxes, which are based on the value of reserves and vary by location, increased to $8.2 million for the year ended December 31, 2007, from $1.6 million in 2006. Operating expenses also increased due to costs associated with the 2007 acquisitions in the Mid-Continent region, including expenses associated with the addition of approximately 150 field and direct field support employees. In addition, the number of producing wells, which increased by over 4,000 gross wells as a result of the acquisitions completed in 2007 and the drilling of 253 wells during the year ended December 31, 2007, and 612 wells from inception through December 31, 2007, also contributed to the increased operating expenses.

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

Average operating expenses per equivalent unit of production increased to $2.18 for the year ended December 31, 2007, compared to $1.67 for the year ended December 31, 2006. Operating expenses per Mcfe increased due to material and labor costs and the changing mix of production beginning in the third quarter of 2006 to include oil and NGL, which have higher operating costs than gas wells. During 2007, the Company also incurred costs for workover and maintenance of its wells to enhance future production and/or offset decline. Operating expenses per Mcfe also increased by $0.09 due to turnover of purchased inventory valued at acquisition cost instead of cost to produce.

General and administrative expenses include the costs of employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. General and administrative expenses increased to approximately $57.2 million for the year ended December 31, 2007, from $40.0 million for the year ended December 31, 2006. The increase in general and administrative expenses was primarily due to costs incurred to support the Company s rapid growth through acquisitions and position the Company for future growth. In conjunction with expansion and development of the organization during 2007, the Company hired approximately 150 employees (including approximately 100 corporate, administrative and support employees with the Mid-Continent acquisition) and as a result, salaries and benefits expense increased approximately $13.5 million over 2006. Costs to perform the necessary functions associated with being a growing company were $14.2 million during 2007, compared to $6.1 million during 2006. These costs include expenses for recruitment of key management team members, acquisition related data conversion and integration, public partnership tax reporting, audit fees, legal fees, proxy and printing costs and other professional fees, including costs related to compliance with Section 404 of the Sarbanes-Oxley Act of 2002. In addition, acquisition costs that are not eligible for capitalization, including internal and indirect costs for completed acquisitions, as well as direct costs associated with acquisition efforts that have not reached fruition, contributed to the increase. The increase in general and administrative expenses was partially offset by lower employee unit-based compensation expense, which decreased to $9.5 million (exclusive of amounts associated with certain of the new employees) during the year ended December 31, 2007, from $21.6 million during 2006. Unit-based compensation expense incurred during the year ended December 31, 2006 was higher compared to that incurred in 2007, primarily due to expense associated with unit awards granted in conjunction with the Company s IPO in January 2006. General and administrative expenses are presented net of approximately $0.9 million and $1.1 million during the years ended December 31, 2007 and 2006, respectively, which represent expense reimbursements from other working interest owners.

The Company incurred expenses of approximately $3.2 million for initial, one-time data license fees during the year ended December 31, 2007. These expenses primarily represent fees for access to 3-D seismic and other data libraries in the Mid-Continent to enable the Company to maximize drilling opportunities in that region.

Depreciation, depletion and amortization increased to approximately $98.0 million for the year ended December 31, 2007, from $24.2 million for the year ended December 31, 2006. Of this increase, approximately $37.9 million was as a result of depletion related to the Mid-Continent acquisition in August 2007. The properties acquired in the Mid-Continent acquisitions earlier in 2007 contributed approximately $12.4 million to the increase. Although total depreciation, depletion and amortization increased during 2007 due to higher total production levels, the reserves in the acquired Texas, Oklahoma and California properties have lower depletion rates than the reserves in the Appalachian Basin. Depreciation, depletion and amortization expenses include impairment expense of $3.3 million and $1.0 million for the years ended December 31, 2007 and 2006, respectively.

Other income and (expenses) increased to a net expense of $94.0 million for the year ended December 31, 2007, compared to a net expense of $28.1 million for the year ended December 31, 2006, primarily due to increased interest expense from increased debt levels associated with borrowings to fund the Mid-Continent acquisition and drilling. Cash payments for interest increased to $57.3 million for the year ended December 31, 2007, compared to $24.1 million for the year ended December 31, 2006. The Company s interest rate swaps were not designated as cash flow hedges under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, (SFAS 133), even though they reduce exposure to changes in interest rates (see Note 8). Therefore, the changes in fair values of these instruments were recorded as a loss of approximately $29.5 million and a gain of approximately $82,000 for the years ended December 31, 2007 and 2006, respectively.

These amounts are non-cash items.

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

Income tax was an expense of approximately $3.6 million for the year ended December 31, 2007 and a benefit of approximately $3.4 million for the year ended December 31, 2006. The Company is a limited liability company treated as a partnership for federal and state income tax purposes. Certain of the Company s subsidiaries are Subchapter C-corporations subject to corporate income taxes. The Company s taxable subsidiaries generated net operating losses for the year ended December 31, 2006. Management has subsequently recovered expenses through an intercompany charge for services from Linn Operating, Inc. to Linn Energy, which resulted in a corresponding tax expense in the year ended December 31, 2007.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Continued

Results of Operations - Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

The following provides selected financial and operating data for the years indicated:

	Year Ended December 31, 2006	Year Ended December 31, 2005	Variance
		(in thousands)	
Revenues:			
Gas sales	$ 61,641	$ 43,594	$ 18,047
Oil sales	18,752	1,051	17,701
Total oil and gas sales	80,393	44,645	35,748
Gain (loss) on oil and gas derivatives **(1)**	103,308	(76,193)	179,501
Natural gas marketing revenues	5,598	4,722	876
Other revenues	1,759	345	1,414
Total revenues	$ 191,058	$ (26,481)	$ 217,539
Expenses:			
Operating expenses	$ 18,099	$ 7,356	$ 10,743
Natural gas marketing expenses	4,862	4,401	461
General and administrative expenses	39,993	3,332	36,661
Depreciation, depletion and amortization	24,173	7,294	16,879
Total expenses	$ 87,127	$ 22,383	$ 64,744
Other income and (expenses)	$ (28,148)	$ (7,413)	$ (20,735)

	Year Ended December 31, 2006	Year Ended December 31, 2005	Variance
Production:			
Gas production (MMcf)	8,599	4,720	82.2%
Oil production (MBbls)	370	20	1750.0%
Total production (MMcfe)	10,818	4,839	123.6%
Average daily production (MMcfe/d)	29.6	13.3	122.6%
Weighted average prices (hedged): (1)			
Gas (Mcf)	$ 9.79	$ 6.45	51.8%
Oil (Bbl) **(2)**	$ 58.68	$ 52.55	11.7%
Weighted average prices (unhedged): (3)			
Gas (Mcf)	$ 7.17	$ 9.24	(22.4)%
Oil (Bbl) **(2)**	$ 50.68	$ 52.55	(3.6)%
Average unit costs per Mcfe of production:			
Operating expenses	$ 1.67	$ 1.52	9.9%
General and administrative expenses **(4)**	$ 3.70	$ 0.69	436.2%
Depreciation, depletion and amortization	$ 2.23	$ 1.51	47.7%

(1) During the year ended December 31, 2005, the Company cancelled (before the original settlement date) a portion of out-of-the money gas swaps and realized a loss of $38.3 million. The Company subsequently hedged similar volumes at higher prices. Weighted average prices (hedged), include the effect of realized gains of $25.5 million and realized losses $13.1 million (excluding the $38.3 million loss) on derivatives for the years ended December 31, 2006 and 2005, respectively.

(2) Oil production in California is sold pursuant to a long-term contract at 79% of NYMEX, and with gravity increase due to NGL being mixed into the oil stream, prices realized average approximately 82% of NYMEX.

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

(4) The measure for the year ended December 31, 2006 includes approximately $21.6 million of unit-based compensation expense and approximately $2.0 million of IPO bonuses. Excluding these amounts, general and administrative expenses for the year ended December 31, 2006 was $1.51 per Mcfe. This is a non-GAAP measure used by Company management to analyze its performance.

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

Revenues

Oil and gas sales increased to approximately $80.4 million for the year ended December 31, 2006, from $44.6 million for the year ended December 31, 2005.

The increase in revenue from oil and gas sales was primarily attributable to increased production. Total production increased to 10,818 MMcfe during the year ended December 31, 2006, from 4,839 MMcfe during the year ended December 31, 2005. Oil production increased to 370 MBbls during the year ended December 31, 2006, from 20 MBbls during the year ended December 2005, primarily due to the acquisition of Blacksand in August 2006. Gas production increased to 8,599 MMcf during the year ended December 31, 2006, from 4,720 MMcf during the year ended December 31, 2005. The increase in gas production was due to the drilling of new wells and production added by the acquisitions of oil and gas properties during 2006 and 2005. The company drilled 159 wells during 2006 and 110 wells in 2005.

Hedging Activities

During the year ended December 31, 2006, the Company entered into commodity pricing derivative contracts for approximately 108% of gas production and 50% of oil production, which resulted in revenues that were $25.5 million greater than the Company would have achieved at unhedged prices. During the year ended December 31, 2005, the Company entered into commodity pricing derivative contracts for approximately 84% of oil and gas production, which resulted in revenues that were $13.1 million less than the Company would have achieved at unhedged prices. During the year ended December 31, 2005, the Company canceled (before its original settlement date) a portion of out-of-the-money gas hedges and realized a loss of $38.3 million, then subsequently hedged similar volumes at higher prices. Unrealized gain on derivatives in the amount of $77.8 million for the year ended December 31, 2006 and unrealized losses on derivatives in the amounts of $24.8 million for the year ended December 31, 2005 were also recorded. Unrealized gains and losses result from oil and gas price fluctuations as compared to the settlement price on the derivative.

Expenses

Operating expenses include expenses such as lease operating, labor, field office, vehicle, supervision, transportation, maintenance, tools, supplies, and production and ad valorem taxes. Production taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by location and are based on the value of reserves. Operating expenses increased to $18.1 million for the year ended December 31, 2006, from $7.4 million for the year ended December 31, 2005, due to the increase in the number of producing wells as a result of the acquisitions completed in both 2006 and 2005 and the drilling of 159 wells during 2006 and 110 wells during 2005. From inception through December 31, 2006, the Company drilled 359 wells and acquired 3,344 wells.

General and administrative expenses include the costs of employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. General and administrative expenses increased to $40.0 million, for the year ended December 31, 2006, from $3.3 million for the year ended December 31, 2005. The increase in general and administrative expenses was due to the recognition of unit-based compensation expense of $21.6 million during the year ended December 31, 2006, compared to none during the year ended December 31, 2005. In addition, acquisition costs that are not eligible for capitalization, including internal and indirect costs for completed acquisitions, as well as direct costs associated with acquisition efforts that have not reached fruition, contributed to the increase. Costs to support rapidly growing operations and position the Company for future growth include increasing staffing levels to manage the 359 wells drilled and 3,344 wells acquired from inception in 2003 through December 31, 2006, recruiting key management team members and performing the functions associated with being a public company, which totaled approximately $6.1 million in 2006 (the year of IPO). General and administrative expenses are presented net of approximately $1.1 million and $1.2 million during the year ended December 31, 2006 and 2005, respectively, which represent expense reimbursements from other working interest owners.

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

Depreciation, depletion and amortization increased to $24.2 million for the year ended December 31, 2006, from $7.3 million for the year ended December 31, 2005. Of this increase, approximately $4.8 million was as a result of depletion related to the properties that were acquired in the Western and Mid-Continent regions in the third quarter of 2006. In addition, the depletion rate for oil and gas properties in the Appalachia Basin increased 37.4% in the fourth quarter of 2006, due to a downward revision of estimated reserves from the prior year. The Company also recorded $1.0 million of impairments during the year ended December 31, 2006.

Other income and (expenses) increased to a net expense of $28.1 million for the year ended December 31, 2006, compared to a net expense of $7.4 million for the year ended December 31, 2005, primarily due to increased debt levels associated with acquisitions and drilling. Cash payments for interest increased to $24.1 million for the year ended December 31, 2006, from $6.5 million for the year ended December 31, 2005. Interest rate swaps were not designated as cash flow hedges under SFAS 133, even though they reduce exposure to changes in interest rates. Therefore, the changes in fair values of these instruments were recorded as gains of approximately $82,000 and $1.0 million for the years ended December 31, 2006 and 2005, respectively. These amounts are non-cash gains.

Income tax was a benefit of approximately $3.4 million for the year ended December 31, 2006. Income tax expense was approximately $74,000 for the year ended December 31, 2005. Linn Energy is a limited liability company, and is taxed substantially as a partnership; however, the Company s taxable subsidiaries generated net operating losses for the year ended December 31, 2006. The increase in realizable net operating loss income tax benefit currently realizable was the result of a 2006 backlog of expenses reported by the taxable subsidiaries on behalf of the consolidated Company. Such losses were realized in 2007 since the strategy of the corporate structure for the taxable subsidiaries is to recover costs rather than generate significant profits and the forecast of loss generation is not expected to turn around in the foreseeable future.

Liquidity and Capital Resources

The Company has utilized public and private equity, proceeds from bank borrowings and cash flow from operations for capital resources and liquidity. To date, the primary use of capital has been for the acquisition and development of oil and gas properties. The Company manages its working capital and cash requirements to borrow only as needed from its credit facility. At December 31, 2007, the Company s total current liabilities exceeded current assets by $59.6 million due to a $65.3 million current payable for post-closing settlement costs for an oil and gas acquisition. The Company has $354.5 in available borrowing to meet such obligations at December 31, 2007.

As the Company pursues growth, it continually monitors the capital resources available to meet future financial obligations and planned capital expenditures. The Company s future success in growing reserves and production will be highly dependent on the capital resources available and its success in drilling for or acquiring additional reserves. The Company actively reviews acquisition opportunities on an ongoing basis. If the Company were to make significant additional acquisitions for cash, it would need to borrow additional amounts under the credit facility, if available, or obtain additional debt or equity financing. The credit facility imposes certain restrictions on the Company s ability to obtain additional debt financing. Based upon current expectations, the Company believes liquidity and capital resources will be sufficient for the conduct of its business and operations.

Statements of Cash Flows Operating Activities

At December 31, 2007, the Company had $1.4 million cash and cash equivalents compared to $6.6 million at December 31, 2006. Cash used by operating activities for the year ended December 31, 2007 was approximately $44.8 million, compared to cash provided by operating activities of $6.8 million for the year ended December 31, 2006. The decrease in cash provided by operating activities was primarily due to premiums paid for derivatives of approximately $279.3 million. The premiums paid were for derivative contracts that hedge 284,985 MMcfe of future production for $2.68 billion of oil and gas property acquisitions (see Note 2) for up to five years. These hedges are expected to provide or stabilize the Company s future cash flow and were funded through the Company s credit facility. See Note 9 for additional details about commodity derivatives.

As part of its overall strategy, the Company regularly enters into long-term commodity derivative contracts in the form of swaps and puts to hedge its future production. The Company s intent is to hold these contracts to maturity. As is common in the marketplace, the Company at times is required to pay cash premiums to enter into such contracts. The majority of the Company s premiums to date have been paid on put contracts, since these contracts contain optionality related to changes in future prices that allow the Company to realize increased cash flows should future prices increase. The derivative contracts hedge the Company s future production as the contracts provide the Company with a minimum realizable cash flow related to its hedged future production. The Company typically enters into additional put and swap contracts in conjunction with the acquisition of oil and gas properties, since its future production

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Continued

increases at that time. In order to hedge the significant increase in production anticipated as a result of its August 2007 and January 2008 acquisitions (see Note 2), the Company purchased additional commodity derivative contracts in the third and fourth quarters of 2007 and paid premiums of approximately $226.3 million for these contracts. The Company expects to purchase additional derivative contracts in the future, as it acquires additional oil and gas properties. The amount of derivative contracts the Company enters into in the future will be directly related to expected production from future acquisitions, and cannot be predicted at this time. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk, for details about derivatives the Company entered into subsequent to December 31, 2007.

Statements of Cash Flows Investing Activities

Cash used in investing activities was approximately $2.89 billion for the year ended December 31, 2007, compared to $551.6 million for the year ended December 31, 2006. The increase in cash used in investing activities was primarily due to an increase in acquisition activity during the year ended December 31, 2007, compared to the same period of the prior year.

The total cash used in investing activities for the year ended December 31, 2007 includes $2.03 billion for the August 2007 acquisition of properties in the Mid-Continent, $555.5 million for the February, June and October 2007 acquisitions in the Mid-Continent and $38.6 million for the acquisitions of certain gas properties in West Virginia (see Note 2). Other acquisitions, including acquisitions of additional working interests in current wells, were approximately $41.5 million and property, plant and equipment purchases were $17.9 million. The total for the year ended December 31, 2007 also includes $185.5 million for the drilling and development of oil and gas properties and pipeline costs. For 2008, the Company estimates its total drilling and development capital expenditures will be between $250.0 million and $300.0 million. This estimate is under continuous review and is subject to on-going adjustment.

Statements of Cash Flows Financing Activities

Cash provided by financing activities was approximately $2.93 billion for the year ended December 31, 2007, compared to $554.0 million for the year ended December 31, 2006.

The Company recorded gross proceeds of $2.12 billion from three private placements of its units during the year ended December 31, 2007. The net proceeds of approximately $2.09 billion were used to finance the Mid-Continent acquisitions, the acquisitions of certain gas properties in West Virginia, and to repay indebtedness under the Company s credit facility. During the year ended December 31, 2007, total proceeds from the issuance of debt were $1.3 billion and total repayments of debt were $283.1 million.

Distributions

Under the limited liability company agreement, Company unitholders are entitled to receive a quarterly distribution of available cash to the extent there is sufficient cash from operations after establishment of cash reserves and payment of fees and expenses. The following provides a summary of distributions paid by the Company during the year ended December 31, 2007:

Date Paid	Period Covered by Distribution	Distribution Per Unit	Total Distribution (in thousands)
November 2007	July 1 - September 30, 2007	$ 0.57	$ 64,798
August 2007	April 1 - June 30, 2007	$ 0.57	37,419
May 2007	January 1 - March 31, 2007	$ 0.52	30,001
February 2007	October 1 - December 31, 2006	$ 0.52	22,745
			$ 154,963

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

In January 2008, the Company s Board of Directors declared a cash distribution of $0.63 per unit with respect to the fourth quarter of 2007. The distribution totaled approximately $72.2 million and was paid on February 14, 2008 to unitholders of record as of the close of business on February 8, 2008. This distribution represents a 10.5% increase in the Company s annualized cash distribution rate, to $2.52 per unit, from $2.28 per unit for the third quarter of 2007.

Private Placements

See Executive Summary above and Note 4 for details about the Company s private placements.

Credit Facility

At December 31, 2007, the Company had a $1.8 billion Third Amended and Restated Credit Agreement (Credit Facility) and a maturity of August 2010. In connection with its Credit Facility, the Company paid approximately $9.3 million in financing fees, which were deferred and are amortized over the life of the Credit Facility. In addition, during the year ended December 31, 2007, the Company wrote off deferred financing fees related to its prior credit facility of approximately $2.8 million. On January 31, 2008, the Credit Facility was amended to increase the amount available for borrowing to $1.9 billion, all of which is conforming, effective until April 1, 2008, at which point the borrowing base will be redetermined in accordance with the terms of the Credit Facility. At January 31, 2008, the Company had $314.5 million available for borrowing under its Credit Facility.

The borrowing base under the Credit Facility will be redetermined semi-annually by the lenders in their sole discretion, based on, among other things, reserve reports as prepared by reserve engineers taking into account the oil and gas prices at such time. The Company s obligations under the Credit Facility are secured by mortgages on its oil and gas properties as well as a pledge of all ownership interests in its operating subsidiaries. The Company is required to maintain the mortgages on properties representing at least 80% of its oil and gas properties. Additionally, the obligations under the Credit Facility are guaranteed by all of the Company s operating subsidiaries and may be guaranteed by any future subsidiaries.

At the Company s election, interest on borrowings under the Credit Facility is determined by reference to either LIBOR plus an applicable margin between 1.00% and 2.25% per annum or the alternate base rate (ABR) plus an applicable margin between 0% and 0.75% per annum. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans.

The Credit Facility contains various covenants that limit the Company s ability to incur indebtedness, enter into interest rate swaps, grant certain liens, make certain loans, acquisitions, capital expenditures and investments, make distributions other than from available cash, merge or consolidate, or engage in certain asset dispositions, including a sale of all or substantially all of its assets. The Credit Facility also contains covenants that require the Company to maintain Adjusted EBITDA to interest expense and current liquidity financial ratios. The Company is in compliance with all financial and other covenants of its Credit Facility.

As noted above, the Company depends on its Credit Facility for future capital needs. In addition, the Company has drawn on the Credit Facility to fund or partially fund quarterly cash distribution payments, since it uses operating cash flows for investing activities and borrows as cash is needed. Absent such borrowing, the Company would have at times experienced a shortfall in cash available to pay the declared quarterly cash distribution amount. If there is a default under the Credit Facility, the Company would be unable to make borrowings to fund distributions.

Term Loan

On January 31, 2008, in order to fund a portion of the January 2008 acquisition of oil and gas properties in the Mid-Continent (see Recent Developments above), the Company entered into a $400.0 million Second Lien Term Loan Agreement with a maturity of July 31, 2009 (Term Loan). In connection with the Term Loan, the Company paid financing fees of approximately $6.0 million, which were deferred and amortized over the life of the Term Loan. The Company s obligations under the Term Loan are secured by a second priority lien on all oil and gas properties as well as a second priority pledge on all ownership interests in its operating subsidiaries. The Company s obligations under the Term Loan are guaranteed by all the Company s operating subsidiaries and may be guaranteed

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

by any future subsidiaries. Covenants under the Term Loan are substantially similar to those under the Credit Facility. Interest is determined by reference to LIBOR plus an applicable margin of 5.0% for the first twelve months and 7.5% for the remaining period until maturity or a domestic bank rate plus an applicable margin of 3.5% for the first twelve months and 6.0% for the remaining period until maturity.

Off-Balance Sheet Arrangements

At December 31, 2007, the Company did not have any off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on its financial position or results of operations.

Contingencies

During the years ended December 31, 2007, 2006, and 2005 no significant payments were made to settle any of the Company s legal proceedings. The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Continued

Commitments and Contractual Obligations

The following summarizes, as of December 31, 2007, certain long-term contractual obligations that are reflected in the consolidated balance sheet and/or disclosed in the accompanying notes thereto:

Contractual Obligations	Total	2008	2009 2010	2011 2012	2013 and Beyond
	Payments Due (in thousands)				
Long-term debt obligations:					
Long-term notes payable	$ 1,521	$ 691	$ 501	$ 47	$ 282
Credit Facility	1,443,000		1,443,000		
Interest on Credit Facility computed at 7.02%	261,688	101,299	160,389		
Operating lease obligations:					
Office, property and equipment leases	15,947	2,752	5,696	4,933	2,566
Other noncurrent liabilities:					
Asset retirement obligations	29,073			204	28,869
Other:					
Derivative instruments	69,961	6,148	48,582	5,568	9,663
Drilling and other contracts	24,136	8,206	15,827	103	
Total	$ 1,845,326	$ 119,096	$ 1,673,995	$ 10,855	$ 41,380

Capital Structure

The Company s capitalization is presented below:

	December 31, 2007	December 31, 2006
	(in thousands)	
Cash and cash equivalents	$ 1,441	$ 6,595
Credit facility	$ 1,443,000	$ 425,750
Other noncurrent debt	830	2,487
	1,443,830	428,237
Total unitholders capital	2,026,641	450,954
Total capitalization	$ 3,470,471	$ 879,191

Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Continued

Non-GAAP Financial Measure

Adjusted EBITDA

The Company defines Adjusted EBITDA as net income (loss) plus:

- Net operating cash flow from acquisitions, effective date through closing date;
- Interest expense, net of amounts capitalized;
- Depreciation, depletion and amortization;
- Write-off of deferred financing fees and other;
- (Gain) loss on sale of assets;
- Accretion of asset retirement obligation;
- Unrealized (gain) loss on derivatives;
- Unit-based compensation and unit warrant expense;
- Data license expenses;

- IPO cash bonuses; and

- Income tax (benefit) provision.

Adjusted EBITDA is a significant performance metric used by Company management to indicate (prior to the establishment of any reserves by its Board of Directors) the cash distributions the Company expects to pay unitholders. Specifically, this financial measure indicates to investors whether or not the Company is generating cash flow at a level that can sustain or support an increase in its quarterly distribution rates. Adjusted EBITDA is also a quantitative metric used throughout the investment community with respect to publicly-traded partnerships and limited liability companies.

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

	Year Ended December 31,		
	2007	**2006**	**2005**
	(in thousands)		
Net income (loss)	$ (364,349)	$ 79,185	$ (56,351)
Plus:			
Net operating cash flow from acquisitions, effective date through closing date (1)	67,417	712	
Interest expense, net of amounts capitalized	62,130	25,494	7,040
Depreciation, depletion and amortization	97,964	24,173	7,294
Write-off of deferred financing fees and other	3,460	3,342	381
(Gain) loss on sale of assets	813	72	39
Accretion of asset retirement obligation	1,014	314	172
Unrealized (gain) loss on derivatives	418,281	(77,776)	24,776
Realized loss on canceled gas derivatives (2)			38,281
Unit-based compensation expense and unit warrant expense	13,921	21,643	
Data license expenses	3,231		
IPO cash bonuses		2,039	
Income tax (benefit) provision (3)	3,573	(3,402)	74
Adjusted EBITDA	$ 307,455	$ 75,796	$ 21,706

(1) Includes net operating cash flow from acquisitions through the date of this report, including the Mid-Continent IV acquisition (see Note 2).

(2) During the year ended December 31, 2005, the Company canceled (before their original settlement date) a portion of out-of-the-money gas swaps and realized a loss of $38.3 million. The Company subsequently hedged similar volumes at higher prices.

(3) The Company s taxable subsidiaries generated net operating losses during the year ended December 31, 2006. Management subsequently recovered expenses through an intercompany charge for services from Linn Operating, Inc. to Linn Energy, which resulted in a corresponding tax expense during the year ended December 31, 2007.

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

As noted above, Adjusted EBITDA is non-GAAP performance measure used by Company management to indicate the cash distributions the Company expects to pay unitholders. On the consolidated statements of cash flows, net cash used by operating activities for the year ended December 31, 2007, was approximately $44.8 million and includes approximately $279.3 million invested in derivatives. Net cash used by operating activities for the year ended December 31, 2006, was approximately $6.8 million and includes $49.8 million invested in derivatives. Net cash used by operating activities for the year ended December 31, 2005 was approximately $29.5 million and includes a $38.3 million realized loss on cancelled out-of-the-money gas swaps.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company s financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles (GAAP). The preparation of these financial statements requires the Company to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates its estimates and assumptions on a regular basis. The Company bases estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in the preparation of financial statements. Below, the Company has provided expanded discussion of its more significant accounting policies, estimates and judgments. These accounting policies reflect more significant estimates and assumptions used in the preparation of financial statements. See Note 1 for a discussion of additional accounting policies and estimates made by Company management.

Oil and Gas Reserves

The Company s estimates of proved reserves are based on the quantities of oil, gas and NGL that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. The independent engineering firm DeGolyer and MacNaughton prepared a reserve and economic evaluation of all of the Company properties on a well-by-well basis as of December 31, 2007.

Reserves and their relation to estimated future net cash flows impact the Company s depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The Company prepares its reserve estimates, and the projected cash flows derived from these reserve estimates, in accordance with SEC guidelines. The independent engineering firm described above adheres to the same guidelines when preparing their reserve reports. The accuracy of the reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

The Company s proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil, gas and NGL eventually recovered.

Oil and Gas Properties/Property and Equipment

Proved Oil and Gas Properties

The Company accounts for oil and gas properties under the successful efforts method. Under this method, all acquisition and development costs of proved properties are capitalized and amortized on a unit-of-production basis over the remaining life of the proved reserves and proved developed reserves, respectively.

The Company evaluates the impairment of its proved oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate an asset s carrying amount may not be recoverable. The carrying amount of proved oil and gas properties are reduced to fair value when the expected undiscounted future cash flows

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

are less than the asset s net book value. Cash flows are determined based upon reserves using prices, costs and discount factors consistent with those used for internal decision making. The underlying commodity prices embedded in the Company s estimated cash flows are the product of a process that begins with the Henry Hub forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices. Although prices used are likely to approximate market, they do not necessarily represent current market prices. Costs of retired, sold or abandoned properties that constitute a part of an amortization base are charged or credited, net of proceeds, to accumulated depreciation, depletion and amortization unless doing so significantly affects the unit-of-production amortization rate, in which case a gain or loss is recognized currently. Gains or losses from the disposal of other properties are recognized currently. Expenditures for maintenance and repairs necessary to maintain properties in operating condition are expensed as incurred. Major replacements are capitalized. Estimated dismantlement and abandonment costs for oil and gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved Oil and Gas Properties

Unproved properties consist of costs incurred to acquire unproved leasehold as well as costs incurred to acquire unproved resources. Unproved leasehold costs are capitalized and amortized on a composite basis if individually insignificant, based on past success, experience and average lease-term lives. Unamortized leasehold costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. The carrying value of the Company s unproved resources, which were acquired in connection with business acquisitions, was determined using the market-based weighted average cost of capital rate, subjected to additional project-specific risking factors. Because these reserves do not meet the definition of proved reserves, the related costs are not classified as proved properties. As the unproved resources are developed and proven, the associated costs are reclassified to proved properties and depleted on a unit-of-production basis. The Company assesses unproved resources for impairment annually by comparing book value to fair value, which is determined using discounted estimates of future cash flows.

Other Property and Equipment

Other property and equipment includes gas gathering systems, pipelines, buildings, data processing and telecommunications equipment, office furniture and equipment, and other fixed assets. These items are recorded at cost and are depreciated using the straight-line method based on expected lives ranging from 3 to 39 years for the individual asset or group of assets.

Goodwill

Goodwill represents the excess of the cost of an acquired business over the net amounts assigned to assets acquired and liabilities assumed. Goodwill is not amortized to earnings but is tested annually during the fourth quarter or whenever events or changes in circumstances indicate that the carrying value may not be recoverable. At December 31, 2007, goodwill on the Company s consolidated balance sheet of $64.4 million represents goodwill recorded in the fourth quarter of 2007 in connection with the Company s Mid-Continent III acquisition (see Note 2). Future changes in goodwill may result from, among other things, finalization of preliminary purchase price allocations, impairments, or future acquisitions.

Revenue Recognition

Sales of oil, gas and NGL are recognized when oil, gas or NGL has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured, and the sales price is fixed or determinable. Virtually all of the Company s contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, gas and NGL, and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

The Company has elected the entitlements method to account for gas imbalances. Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Under the entitlements method, any amount received in excess of the Company s share is treated as a liability. If the Company receives

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

less than its entitled share, the underproduction is recorded as a receivable. At December 31, 2007, the Company had a gas imbalance receivable of approximately $6.6 million, which is included in accounts receivable trade, net, on the consolidated balance sheet. The Company did not have any significant gas imbalance positions at December 31, 2006.

The Company engages in the purchase, gathering and transportation of third-party natural gas and subsequently markets such gas to independent purchasers under separate arrangements. As such, the Company separately reports third-party marketing sales and natural gas marketing expenses. Marketing margins related to the Company s production are included in oil, gas and NGL sales.

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

Asset Retirement Obligations

The Company has the obligation to plug and abandon oil and gas wells and related equipment at the end of production operations. Estimated asset retirement costs are recognized when the obligation is incurred, and are amortized over proved developed reserves using the units of production method. Asset retirement costs are estimated by the Company s engineers using existing regulatory requirements and anticipated future inflation rates. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations (see Note 11).

Derivative Instruments

The Company uses derivative financial instruments to achieve a more predictable cash flow from its oil, gas and NGL production by reducing its exposure to price fluctuations. As of December 31, 2007, these transactions were in the form of swaps and puts. A put option requires the Company to pay the counterparty a premium equal to the fair value of the option at the purchase date and receive from the counterparty the excess, if any, of the fixed floor over the floating market price. Additionally, the Company uses derivative financial instruments in the form of interest rate swaps to mitigate its interest rate exposure.

The Company accounts for these activities pursuant to SFAS 133. This statement establishes accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the balance sheet as assets or liabilities. The Company accounts for its derivatives at fair value as an asset or liability and the change in the fair value of the derivatives is included in earnings since none of the Company s commodity or interest rate derivatives are designated as hedges under SFAS 133. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for discussion regarding the Company s sensitivity analysis for the Company s financial instruments and interest rate swaps.

Purchase Accounting

The establishment of the asset base through the date of this report has included 22 acquisitions of working interests in oil and gas properties. These acquisitions have been accounted for using the purchase method of accounting as prescribed in SFAS No. 141, *Business Combinations.* See Note 2 for additional details about acquisitions.

In connection with a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based on independent appraisals, discounted cash flows, quoted market prices and estimates by management. In addition, when appropriate, the Company reviews comparable purchases and sales of oil and gas properties within the same regions, and uses that data as a proxy for fair market value; i.e., the amount a willing buyer and seller would enter into in exchange for such properties. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

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

The Company made various assumptions in estimating the fair values of assets acquired and liabilities assumed. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and gas properties. To estimate the fair values of these properties, the Company prepared estimates of oil and gas reserves. The Company estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate was subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable and possible reserves were reduced by additional risk-weighting factors.

Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

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

Unit-Based Compensation

The Company accounts for unit-based compensation pursuant to SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS 123R). SFAS 123R requires an entity to recognize the grant-date fair-value of stock options and other equity-based compensation issued to employees in the income statement and eliminates the alternative to use the intrinsic value method of accounting that was provided under the original provisions of SFAS 123, which resulted in no compensation expense recorded in the financial statements related to the issuance of equity awards to employees. It establishes fair value as the measurement objective in accounting for share-based payment arrangements and requires companies to apply a fair-value-based measurement method in accounting for share-based payment transactions with employees. The Company also follows the guidance in Staff Accounting Bulletin (SAB) No. 107, *Share-Based Payment,* which contains the express views of the SEC staff regarding the interaction between SFAS 123R and certain SEC rules and regulations and provides the staff s views regarding the valuation of share-based payment arrangements for public companies. The Company recorded no unit-based compensation expense for the year ended December 31, 2005, as there were no unit-based payments made during that year. See Note 6 for additional details about the Company s accounting for unit-based compensation.

New Accounting Pronouncements

There have been no new accounting standards that materially affected the Company this period; however, see Note 15 for details regarding FIN 48.

See Note 1 for details regarding the Company s change in accounting policy related to the balance sheet presentation of derivative instruments in accordance with the provisions of FASB Interpretation No. 39, *Offsetting of Amounts Related to Certain Contracts.*

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

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

Commodity Price Risk

The Company s major market risk exposure is in the pricing applicable to oil, gas and NGL production. Realized pricing is primarily driven by the spot market prices applicable to production and the prevailing price for oil, gas and NGL. Pricing for oil, gas and NGL production has been historically volatile and unpredictable, and this volatility is expected to continue in the future. The prices the Company receives for production depend on many factors outside of its control.

The Company enters into hedging arrangements with respect to a portion of its projected production through various transactions that hedge the future prices received. See Note 9 for additional details. These transactions may include price swaps whereby the Company will receive a fixed price for production and pay a variable market price to the contract counterparty. At the settlement date, the Company receives the excess, if any, of the fixed NYMEX or PEPL price floor over the floating rate. Additionally, the Company has put options for which it pays the counterparty the fair value at the purchase date. These hedging activities are intended to support commodity prices at targeted levels and to manage exposure to oil, gas and NGL price fluctuations.

At December 31, 2007, the fair value of hedges that settle during the next twelve months was an asset of approximately $22.3 million and a liability of approximately $3.9 million for a net asset of approximately $18.4 million, which the Company is owed by counterparties. A 10% increase in the index oil and gas prices above the December 31, 2007 prices for the next twelve months would result in a reduction in the value of the hedges of approximately $53.9 million; conversely, a 10% decrease in the index oil and gas prices would result in an increase of approximately $56.5 million.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Continued

The following table summarizes, as of February 22, 2008, and for the periods indicated, derivatives in place through December 31, 2013.

	February 22 - December 31, 2008	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013
Gas Positions:						
Fixed Price Swaps:						
Hedged Volume (MMMBtu)	41,134	49,271	42,086	38,741	34,066	
Average Price ($/MMBtu)	$ 8.48	$ 8.32	$ 8.14	$ 8.08	$ 8.45	$
Puts:						
Hedged Volume (MMMBtu)	5,883	6,960	6,960	6,960		
Average Price ($/MMBtu)	$ 8.07	$ 7.50	$ 7.50	$ 7.50	$	$
PEPL Puts: (1)						
Hedged Volume (MMMBtu)	3,212	5,334	10,634	13,259	5,934	
Average Price ($/MMBtu)	$ 7.85	$ 7.85	$ 7.85	$ 7.85	$ 7.85	$
Total:						
Hedged Volume (MMMBtu)	50,229	61,565	59,680	58,960	40,000	
Average Price ($/MMBtu)	$ 8.39	$ 8.19	$ 8.02	$ 7.96	$ 8.36	$
Oil Positions:						
Fixed Price Swaps:						
Hedged Volume (MBbls)	2,364	2,437	2,150	2,073	2,025	900
Average Price ($/Bbl)	$ 82.42	$ 78.07	$ 78.28	$ 79.65	$ 77.65	$ 72.22
Puts: (2)						
Hedged Volume (MBbls)	1,557	1,843	2,250	2,352	500	
Average Price ($/Bbl)	$ 73.34	$ 72.13	$ 70.56	$ 69.11	$ 77.73	$
Total:						
Hedged Volume (MBbls)	3,921	4,280	4,400	4,425	2,525	900
Average Price ($/Bbl)	$ 78.81	$ 75.51	$ 74.33	$ 74.05	$ 77.66	$ 72.22
Gas Basis Differential Positions:						
PEPL Basis Swaps: (3)						
Hedged Volume (MMMBtu)	30,122	34,666	29,366	26,741	34,066	
Hedged Differential ($/MMBtu)	$ (0.95)	$ (0.95)	$ (0.95)	$ (0.95)	$ (0.95)	$

(1) Settle on the PEPL spot price of gas to hedge basis differential associated with gas production in the Mid-Continent region.

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

(3) Represents a swap of the basis between NYMEX and the PEPL spot price of gas of $(0.95) per MMBtu for the volumes hedged.

Interest Rate Risk

At December 31, 2007, the Company had long-term debt outstanding of $1.44 billion under its Credit Facility, which incurred interest at floating rates in accordance the Credit Facility agreement. See Note 7 for additional details about the Credit Facility. As of December 31, 2007, the interest rate based on LIBOR was approximately 7.02%. A 1% increase in LIBOR would result in an estimated $12.5 million increase in annual interest expense associated with the Credit Facility.

The Company has entered into interest rate swap agreements based on LIBOR to minimize the effect of fluctuations in interest rates. If LIBOR is lower than the fixed rate in the contract, the Company is required to pay the counterparties the difference, and conversely, the counterparties are required to pay the Company if LIBOR is higher than the fixed rate in the contract. See Note 8 for additional details.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS and SUPPLEMENTARY DATA

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed under the supervision of our Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted in the United States.

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

As of December 31, 2007, our management assessed the effectiveness of the Company s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in *Internal Control Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that we maintained effective internal control over financial reporting as of December 31, 2007, based on those criteria. The Company acquired oil and gas properties from Dominion Resources, Inc. in August 2007 (Dominion Acquisition) and excluded from our assessment of the effectiveness of internal control over financial reporting as of December 31, 2007, Dominion Acquisition s internal control over financial reporting associated with total assets of $2.2 billion and total revenues of $106.1 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2007.

KPMG LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company s internal control over financial reporting as of December 31, 2007, which is included herein.

/s/ Linn Energy, LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Linn Energy, LLC:

We have audited the accompanying consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, unitholders capital (deficit), and cash flows for each of the years in the three-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Linn Energy, LLC and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Linn Energy, LLC s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2008 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas

February 28, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders

Linn Energy, LLC:

We have audited Linn Energy, LLC s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Linn Energy, LLC s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, Linn Energy, LLC maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Linn Energy, LLC s management, in conducting its assessment of internal control over financial reporting as of December 31, 2007, has excluded its oil and gas properties and related assets in the Mid-Continent, which were acquired on August 31, 2007 from Dominion Resources, Inc. and certain affiliates (Dominion), as permitted by the Securities and Exchange Commission. Dominion s total assets were $2.2

billion, or approximately 59% of Linn Energy, LLC s total assets, as of December 31, 2007, and Dominion s total revenues were $106.1 million, or approximately 33% of Linn Energy, LLC s total oil, gas and natural gas liquid sales, for the year ended December 31, 2007. Our audit of internal control over financial reporting of Linn Energy, LLC also excluded an evaluation of the internal control over financial reporting of Dominion.

We also have audited, in accordance with the standards the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Linn Energy, LLC as of December 31, 2007 and 2006, and the related consolidated statements of operations, unitholders capital (deficit) and cash flows for each of the years in the three-year period ended December 31, 2007, and our report dated February 28, 2008 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 28, 2008

LINN ENERGY, LLC

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(in thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 1,441	$ 6,595
Accounts receivable trade, net	138,716	19,124
Inventories	2,350	578
Derivative instruments	26,100	37,353
Other current assets	3,418	5,562
Total current assets	172,025	69,212
Oil and gas properties and equipment (successful efforts method)	3,618,741	766,638
Less accumulated depreciation, depletion and amortization	(127,265)	(33,349)
	3,491,476	733,289
Property and equipment, net	32,024	20,754
Other noncurrent assets:		
Deposit for oil and gas properties	27,619	20,086
Derivative instruments		60,503
Goodwill	64,419	
Other noncurrent assets, net	9,006	2,068
	101,044	82,657
Total assets	$ 3,796,569	$ 905,912
Liabilities and Unitholders Capital		
Current liabilities:		
Accounts payable and accrued expenses	$ 162,058	$ 12,759
Joint interest payable	50,444	1,839
Accrued interest payable	5,802	2,084
Derivative instruments	6,148	
Other current liabilities	7,141	873
Total current liabilities	231,593	17,555
Noncurrent liabilities:		
Credit facility	1,443,000	425,750
Derivative instruments	63,813	423
Asset retirement obligations	29,073	8,594
Other noncurrent liabilities	2,449	2,636
Total noncurrent liabilities	1,538,335	437,403
Unitholders capital:		

113,815,914 units and 33,617,187 units issued and outstanding at December 31, 2007 and 2006, respectively		2,374,660		246,034
9,185,965 Class B units issued and outstanding at December 31, 2006				188,590
Accumulated income (loss)		(348,019)		16,330
		2,026,641		450,954
Total liabilities and unitholders capital	$	3,796,569	$	905,912

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

LINN ENERGY, LLC

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2007	**2006**	**2005**
	(in thousands, except per unit amounts)		
Revenues:			
Oil, gas and natural gas liquid sales	$ 318,226	$ 80,393	$ 44,645
Gain (loss) on oil and gas derivatives	(345,537)	103,308	(76,193)
Natural gas marketing revenues	15,537	5,598	4,722
Other revenues	4,537	1,759	345
	(7,237)	191,058	(26,481)
Expenses:			
Operating expenses	88,527	18,099	7,356
Natural gas marketing expenses	12,596	4,862	4,401
General and administrative expenses	57,188	39,993	3,332
Data license expenses	3,231		
Depreciation, depletion and amortization	97,964	24,173	7,294
	259,506	87,127	22,383
	(266,743)	103,931	(48,864)
Other income and (expenses):			
Interest expense, net of amounts capitalized	(62,130)	(25,857)	(8,043)
Gain (loss) on interest rate swaps	(28,081)	363	1,003
Other expenses, net	(3,822)	(2,654)	(373)
	(94,033)	(28,148)	(7,413)
Income (loss) before income taxes	(360,776)	75,783	(56,277)
Income tax benefit (provision)	(3,573)	3,402	(74)
Net income (loss)	$ (364,349)	$ 79,185	$ (56,351)
Net income (loss) per unit:			
Units basic	$ (5.29)	$ 2.64	$ (2.75)
Units diluted	$ (5.29)	$ 2.61	$ (2.75)
Class B units basic	$	$ 2.64	$
Class B units diluted	$	$ 2.61	$
Weighted average units outstanding:			
Units basic	68,916	28,281	20,518
Units diluted	68,916	30,385	20,518
Class B units basic		1,737	
Class B units diluted		1,737	
Distributions declared per unit	$ 2.18	$ 1.15	$

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

LINN ENERGY, LLC

CONSOLIDATED STATEMENTS OF UNITHOLDERS CAPITAL (DEFICIT)

	Unitholders Capital	Accumulated Income (Loss)	Treasury Units (at Cost)	Total Unitholders Capital (Deficit)
	(in thousands)			
Balance as of December 31, 2004	$ 16,024	$ (6,504)	$	$ 9,520
Net loss		(56,351)		(56,351)
Balance as of December 31, 2005	16,024	(62,855)		(46,831)
Sale of initial public offering units, net of offering expense of $4,339	225,139		13,671	238,810
Sale of private placement units, net of expense of $348	304,652			304,652
Redemption of member units			(114,449)	(114,449)
Cancellation of member units	(100,778)		100,778	
Distribution to members	(32,056)			(32,056)
Unit-based compensation expense	21,643			21,643
Net income		79,185		79,185
Balance as of December 31, 2006	434,624	16,330		