LINN ENERGY, LLC
Form 10-K
March 30, 2007

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, 2006

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	**65-1177591**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
600 Travis Street, Suite 7000 Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code

(281) 605-4100

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 o No **x**

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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer x

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 our voting and non-voting common equity held by non-affiliates of the registrant was approximately $276,160,952 million on June 30, 2006, based on $20.95 per unit, the last reported sales price of the units on The NASDAQ Global Market on such date.

As of February 28, 2007, there were 50,303,019 units outstanding.

As of February 28, 2007, there were 7,465,946 Class C 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 June 19, 2007.

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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:

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.

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.

NGLs. 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.

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.

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%. Our Standardized Measure does not include future income tax expenses because our reserves are owned by our subsidiary Linn Energy Holdings, LLC, which is not subject to income taxes.

Successful well. A well capable of producing oil and/or gas 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 reserves. Lease acreage on which wells have not been drilled and where it is either probable or possible that the acreage contains reserves.

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

Workover. Operations 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 to Linn

When referring to Linn Energy, LLC (Linn or the Company) and using phrases such as we, our, us, or the Company, our intent is to refer and its consolidated subsidiaries as a whole or on a divisional basis, depending on the context in which the statements are made.

Overview

Linn is an independent oil and gas company focused on the development and acquisition of long-lived properties in the United States that began operations in March 2003 and was formed as a Delaware limited liability company in April 2005. Linn is a holding company that conducts its operations through, and its operating assets are owned by, its wholly-owned subsidiaries. We completed our initial public offering (IPO) on January 13, 2006 and our units representing limited liability company interests (units) are listed on The NASDAQ Global Market under the symbol LINE.

Our strategy focuses on building core areas of operations in multiple regions within the United States with long-lived gas or oil reserves. Our core areas include:

- Appalachian Basin, which includes West Virginia, Pennsylvania, New York and Virginia;
- Western, which includes the Brea Olinda Field in the Los Angeles Basin of California;
- Mid-Continent, which includes the Sooner Trend of north central Oklahoma; and
- Texas Panhandle, which includes the Texas portion of the Hugoton-Panhandle Field (acquired in February 2007).

During the year ended December 31, 2006, we completed five acquisitions of oil and gas properties and related gathering and pipeline assets with total proved reserves of 263.7 Bcfe, for an aggregate purchase price of approximately $454.9 million, or an acquisition cost of approximately $1.72 per Mcfe. From inception in March 2003 through December 31, 2006, we completed 14 acquisitions of oil and gas properties and related gathering and pipeline assets, with total proved reserves of approximately 441.5 Bcfe, for an aggregate purchase price of approximately $656.4 million, or, including the amounts allocated to unproved leasehold, an acquisition cost of approximately $1.49 per Mcfe. As part of our business strategy, we continually evaluate opportunities to acquire additional oil and gas properties which complement our asset profile. See Acquisitions below for details about our most recent acquisitions in Texas and West Virginia, which are not included in our reserves at December 31, 2006.

Our proved reserves at December 31, 2006 were 454.1 Bcfe, of which approximately 60.3% were gas and 39.7% were oil. Approximately 69.2% were classified as proved developed, with a total proved Standardized Measure value of $552.3 million. At December 31, 2006, we operated 2,683, or 73.3%, of our 3,659 productive wells. Our average proved reserves-to-production ratio, or average reserve life, is approximately 29.5 years, based on our December 31, 2006 reserve report and annualized production for the fourth quarter ended December 31, 2006.

Item 1. Business and Properties - Continued

Acquisitions

The following table provides a summary of the oil and gas properties we have acquired from inception through the date of this report:

Year	# of Acquisitions	Gross Wells	Location	Aggregate Contract Price (in millions)
2003	4	498	West Virginia, Virginia, New York and Pennsylvania	$ 52.0
2004	2	698	Pennsylvania	25.9
2005	3	718	West Virginia and Virginia	124.5
2006	5	1,430	West Virginia, California and Oklahoma	451.7
2007	3	902	West Virginia and Texas	453.9
	17	4,246		$ 1,108.0

In February 2007, the Company completed the acquisition of certain oil and gas properties and related assets in the Texas Panhandle from Cavallo Energy, LP, acting through its general partner, Stallion Energy LLC (Stallion) for a contract price of $415.0 million, subject to customary post-closing adjustments (see Note 2 in Notes to Consolidated Financial Statements for additional details). In addition, in January 2007, the Company completed the acquisitions of certain gas properties located in the Appalachian Basin of West Virginia for an aggregate contract price of $39.0 million, subject to customary post-closing adjustments. These acquisitions were financed with a combination of private placement of our units and borrowings under the Company s credit facility.

Our acquisitions have been funded by a combination of debt and private placements of our units. During 2006, we completed a private placement of our units raising gross proceeds of $305.0 million and completed another private placement of our units with gross proceeds of $360.0 million in February 2007.

Strategy

Our goal is to provide stability and growth in distributions to our unitholders through continued successful drilling, acquisitions, increasing production of existing wells and pursuing operational and administrative efficiencies. The following is a summary of the key elements of our business strategy:

- acquire properties that increase cash available for distributions;
- build regional scale to maximize value and operating cash flows;
- grow through low risk, low cost development drilling and other enhancements;
- create post-acquisition value; and
- mitigate commodity price risk through hedging.

Certain key elements included in our business strategy are further explained below.

Acquire Properties and Build Regional Scale. Our acquisition program targets oil and gas properties that offer high-quality, long-lived production with predictable decline curves, as well as development drilling opportunities. From March 2003 through the first quarter of 2007, including preliminary estimates for our first quarter 2007 acquisitions, we have purchased approximately 795.0 Bcfe of proved reserves, at a total cost of approximately $1,109.7 million (includes preliminary purchase prices, which are subject to customary post-closing adjustments). Including the amounts allocated to unproved leasehold, our acquisition cost was approximately $1.40 per Mcfe over this time period. Our acquisition program focuses both on acquiring new core areas, where the assets meet our strategic profile, and increasing our ownership in existing fields or core areas. Acquisitions will continue to play a key role in our future growth strategy.

Grow Through Development Activities. We seek to be the operator of our properties to design and develop capital maintenance and development drilling programs that not only replace our production, but add value through the growth of reserves and future operational synergies. During the third quarter of 2006, we acquired two drilling rigs to better manage and control costs related to our drilling programs. In addition to our own rigs, we have contracts in place for third party

Item 1. Business and Properties - Continued

drilling services that, together with our own rigs, provide the resources required to complete our drilling and development program for 2007 and beyond. Most of our wells, excluding those in Oklahoma, are relatively shallow, ranging from 3,000 to 6,000 feet, and drill through multiple productive zones. Our wells in Oklahoma range from 8,000 to 12,000 feet. Many of our wells are completed in multiple producing zones with commingled production. New producing wells generally have a total projected economic life in excess of 50 years. Our recent acquisitions provide an ample inventory of lower-risk development opportunities, which we believe will create post-acquisition value from our assets.

Hedging Program. We typically seek to hedge a significant portion of our anticipated future production volumes to reduce commodity price volatility risk. Managing this volatility, which we believe is likely to continue in the years ahead, provides a longer-term stability of cash flows. We currently have gas hedges in place covering substantially all of our anticipated production for the remainder of 2007 and a significant portion of estimated production from 2008 through 2011, at weighted average NYMEX prices per Btu of $7.80. In addition, we have a majority of our anticipated oil production hedged for the remainder of 2007 through 2011, at weighted average NYMEX prices per Bbl of $67.49. During 2006, settled hedges resulted in gains of approximately $25.5 million.

Core Operating Areas

Appalachian Basin. Our Appalachian Basin proved reserves represented 199.0 Bcfe, or 43%, of our total proved reserves at December 31, 2006, of which 60% were proved developed reserves. During 2006, the Appalachian Basin assets produced 8.0 Bcfe, or 74%, of the Company s 2006 production. During 2006, we invested approximately $43.1 million to drill 155 wells in the Appalachian Basin. In addition, in order to improve our drilling efficiency, we purchased two drilling rigs at a cost of approximately $2.2 million per rig in the latter part of 2006, and an additional rig in the first quarter of 2007. We also own certain pipelines which market and transport our gas as well as transport gas for third parties. In January 2007, we acquired additional reserves that we believe have significant development potential and also expanded our pipeline facilities. During 2007, we anticipate spending 30% to 50% of our total budget for drilling, development and pipeline expansion activities in the Appalachian Basin.

Mid-Continent. Our Mid-Continent proved reserves of 74.0 Bcfe, acquired in third quarter of 2006, represented 16% of our total proved reserves at December 31, 2006, of which 52% were proved developed reserves. This area produced 1.0 Bcfe, or 9%, of the Company s 2006 production. During 2006, we invested approximately $3.9 million to drill four wells in the Mid-Continent. During 2007, we anticipate spending 10% to 15% of our total budget for development activities in the Mid-Continent region.

Western. Our Western operations, also acquired in third quarter of 2006, represented proved reserves of 32.0 MMboe, or 41%, of our total proved reserves at December 31, 2006, of which 87% were proved developed reserves. During 2006, the Western assets produced 312.0 MMboe, or 17%, of the Company s 2006 production. During 2007, we anticipate spending approximately 3% of our total budget for capital maintenance activities in the Brea-Olinda Field. In addition to oil and gas production, our Western operations also include the operation of a gas power generation facility that processes gas produced from our wells as well as third party gas. The power generated is used to reduce our operating costs and any excess power is sold. Reserve estimates related to contracts of third party gas totaled 10.0 Bcfe at December 31, 2006, which are not included in our reserve disclosures or amounts provided above.

Texas Panhandle. In February 2007, we completed our acquisition of oil and gas properties in the Texas Panhandle with proved reserves of approximately 51.0 MMboe, or 10%, of the Company s total proved reserves on a pro forma basis as of December 31, 2006. Of these, approximately 44% were proved developed reserves. We are continuing with the current development plan which deploys two drilling rigs. Currently we are developing our 2007 plan for this area and anticipate spending 30% to 40% of our total budget for drilling and development activities in the Texas Panhandle area.

Drilling Activity

We intend to concentrate our drilling activity on lower risk, development properties. The number, types, and location of wells we drill will vary depending on our capital budget, the cost of each well, anticipated production and the estimated recoverable reserves attributable to each well.

Item 1. Business and Properties - Continued

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

	Year Ended December 31,		
	2006	2005	2004
Gross Wells:			
Productive	154	110	90
Dry	5		
Total	159	110	90
Net Development Wells:			
Productive	147	105	82
Dry	5		
Total	152	105	82
Net Exploratory Wells:			
Productive			
Dry			
Total			

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

Historically, most of our drilling has been in the Appalachian Basin. At December 31, 2006, we had 16 (13.7 net) wells in process. From inception through December 31, 2006, we spent approximately $91.3 million to drill and complete 359 wells, substantially all of which are capable of producing oil and gas in commercial quantities.

The following table sets forth information, as of December 31, 2006, relating to our drilling locations and net acres of leasehold interests in our three core areas at that date:

	Appalachian Basin	Western	Mid-Continent	Total
Proved undeveloped	581	2	133	716
Other locations	538			538
Total drilling locations	1,119	2	133	1,254
Leasehold interests-net acres	174,000	810	53,896	228,706

With our February 2007 acquisition of oil and gas properties in the Texas Panhandle, we added 1,265 drilling locations, 347 of which were identified as proved undeveloped locations and 918 of which were identified as unproved locations.

As shown in the table above, as of December 31, 2006, we had 716 proved undeveloped drilling locations (specific drilling locations as to which our independent engineering firm, DeGolyer and MacNaughton, assigned proved undeveloped reserves as of such date) and we had identified 538 additional unproved drilling locations (specific drilling locations as to which DeGolyer and MacNaughton has not assigned any proved reserves) on acreage that we have under existing leases. As successful development wells frequently result in the reclassification of adjacent lease acreage from unproved to proved, we expect that a significant number of our unproved drilling locations will be reclassified as proved drilling locations prior to the actual drilling of these locations.

Item 1. Business and Properties - Continued

Oil and Gas Prices

Linn s gas production is generally sold under market sensitive price contracts, which typically sell at differentials to the NYMEX gas prices due to the Btu content and the proximity to major consuming markets. Our 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, we receive a percentage of the resale price received by the purchaser for sales of residue gas and natural gas liquids recovered after transportation and processing of our gas. These purchasers sell the residue gas and natural gas liquids based primarily on spot market prices. Under percentage-of-index contracts, the price per MMBtu we receive for our gas is tied to indexes published in *Gas Daily* or *Inside FERC Gas Market Report.* Although exact percentages vary daily, as of February 2007, approximately 80% of our gas production was sold under short-term contracts at market-sensitive or spot prices. Similarly, oil production is generally sold under market sensitive long-term percentage-of-index contracts.

We enter into derivative transactions in the form of hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Currently, we use fixed price swaps and puts to hedge NYMEX oil and gas prices, which do not include the additional net premium we typically realize in the Appalachian Basin for gas. By removing the price volatility from a significant portion of our oil and gas production, we have mitigated, but not eliminated, the potential effects of fluctuating oil and gas prices on our cash flow from operations for those periods.

Oil and Gas Data

Proved Reserves

Proved oil and gas reserves are the estimated quantities of oil and gas 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 and gas 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 Supplementary Oil and Gas Data (Unaudited) in Item 8. Financial Statements and Supplementary Data.

The following table presents our estimated net proved oil and gas reserves and the present value of our estimated proved reserves at December 31, 2006, 2005 and 2004, based on reserve reports prepared by DeGolyer and MacNaughton at December 31, 2006 and reserve reports prepared by Schlumberger Data and Consulting Services at December 31, 2005 and 2004. The Standardized Measure values shown in the table are not intended to represent the market value of our estimated oil and gas reserves at such dates.

	December 31,		
	2006	**2005**	**2004**
Reserve Data: (1)			
Estimated net proved reserves:			
Gas (Bcf)	274.0	191.9	118.9
Oil (MMBbls)	30.0	0.2	0.1
Total (Bcfe)	454.1	193.2	119.8
Proved developed (Bcfe)	314.1	125.2	74.4
Proved undeveloped (Bcfe)	140.0	68.0	45.4
Proved developed reserves as a % of total proved reserves	69.2 %	64.8 %	62.1 %
Standardized Measure (in millions) (2)	$ 552.3	$ 552.1	$ 215.0
Representative Oil and Gas Prices:			
Gas NYMEX Henry Hub per MMBtu	$ 5.64	$ 10.08	$ 6.18
Oil NYMEX West Texas Intermediate per Bbl	$ 61.05	$ 57.98	$ 43.36

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(1) Excludes the Texas Panhandle reserves of 51.0 MMboe and reserves for the two Appalachian Basin acquisitions discussed above.

(2) Does not give effect to derivative transactions. For a description of our derivative transactions, see Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation - Statements of Cash Flows - Operating Activities in this Annual Report on Form 10-K.

Item 1. Business and Properties - Continued

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 our senior engineering staff and management, with final approval by our Chief Operating Officer. The process performed by DeGolyer and MacNaughton to estimate the December 31, 2006 reserve amounts and by Schlumberger Data and Consulting Services to estimate the December 31, 2005 and 2004 reserve amounts included their preparation of our estimated reserve quantities, future producing rates, future net revenue and the present value of such future net revenue. The independent engineering firms also prepared our estimates with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X Rule 4-10 (a) and subsequent Securities and Exchange Commission (SEC) staff interpretations and guidance. In the conduct of their preparation of the reserve estimates, neither DeGolyer and MacNaughton nor Schlumberger Data and Consulting Services independently verified 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 about the recoverability of reserves in future years, under existing economic and operating conditions. We have 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 our 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 used to calculate Standardized Measure, which is required by Statements of Financial Accounting Standards (SFAS) No. 69, *Disclosures about Oil and Gas Producing Activities,* is not necessarily the most appropriate discount rate. 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.

Production and Price History

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

	Year Ended December 31,		
	2006	**2005**	**2004**
Production:			
Gas production (MMcf)	8,599	4,720	3110
Oil production (MBbls)	370	20	10
Total production (MMcfe)	10,818	4,839	3,112
Average daily production (Mcfe/d)	29,638	13,258	8,526
Weighted Average Realized Prices: (1)			
Gas (Mcf)	$ 9.79	$ 6.92	$ 5.73
Oil (Bbl) (2)	$ 58.68	$ 52.55	$ 37.83
Total (Mcfe)	$ 9.79	$ 6.97	$ 5.74

(1) Includes the effect of realized gains and losses on oil and gas derivatives.

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

Item 1. Business and Properties - Continued

Productive Wells

The following table sets forth information relating to the productive wells in which we owned a working interest as of December 31, 2006. Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections to commence deliveries. Gross wells refers to the total number of producing wells in which we have an interest, and net wells refers to the sum of our fractional working interests owned in gross wells.

	Gas Wells		Oil Wells		Total Wells	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Operated (1)	2,301	1,425	380	360	2,681	1,785
Non-operated (2)	819	518	159	71	978	589
Total	3,120	1,943	539	431	3,659	2,374

(1) Three operated wells had multiple completions at December 31, 2006.

(2) One non-operated well had multiple completions at December 31, 2006.

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2006, relating to our leasehold acreage:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Operated	213,086	143,203	65,429	56,279	278,515	199,482
Non-operated	133,300	29,224			133,300	29,224
Total	346,386	172,427	65,429	56,279	411,815	228,706

Oil and Gas Operational Overview

General

We seek to be the operator of wells in which we have an interest. As operator, we design and manage the drilling and enhancement activities and supervise operation and maintenance activities on a day-to-day basis. We purchased two drilling rigs during 2006, an additional rig in the first quarter of 2007, and currently have contracts in place for additional third-party drilling rigs needed to carry out our 2007 drilling program. In the third quarter of 2006, the Company began, for the first time, operating its own drilling rigs, staffed with Company personnel. Company personnel also perform drilling activities using leased equipment, and did so prior to the purchase of its own rigs. In addition, we employ drilling, production and reservoir engineers, geologists and other specialists who work to improve production rates, increase reserves and lower the cost of operating our oil and gas properties.

Principal Customers

For the year ended December 31, 2006, sales of oil and gas to Dominion Resources, Inc. and ConocoPhillips accounted for approximately 53% and 14%, respectively, of our total volumes, or 67% in the aggregate. If we were to lose any one of our major oil and gas purchasers, the loss could temporarily cease or delay production and sale of our oil and gas in that particular purchaser s service area. If we were to lose a purchaser, we believe we 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 we are able to sell.

Competition

The oil and gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects, than our financial or human resources permit.

Item 1. Business and Properties - Continued

We are 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. We are unable to predict when, or if, such shortages may occur or how they would affect our drilling program.

Competition is also strong for attractive oil and gas producing properties, undeveloped leases and drilling rights, and we cannot guarantee that we will be able to compete satisfactorily when attempting to make further acquisitions.

Title to Properties

As it is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties; we are typically responsible for curing any title defects at our expense prior to commencing drilling operations. Prior to completing an acquisition of producing gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, we have obtained title opinions on a significant portion of our oil and gas properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Our oil and gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other operations in certain areas of the United States that we operate in (primarily in parts of the Appalachian Basin and Oklahoma) and, as a result, we perform the majority of our drilling during the summer months in these areas. These seasonal anomalies can pose challenges for meeting our 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 our 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. This can also lessen seasonal demand fluctuations.

Derivative Activity

We enter into derivative transactions with third parties with respect to oil and gas prices and interest rates to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in gas prices and interest rates. For a more detailed discussion of our derivative activities, 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.

Appalachia Gas Gathering Activities

Gathering for Ourselves

In order to more efficiently transport our gas to market, we own and operate a network of gas gathering systems comprised of over 900 miles of pipeline and associated compression and metering facilities which connect to numerous sales outlets on eight interstate and eight intrastate pipelines. The interstate market outlets are Dominion Transmission Inc. (West Virginia and Pennsylvania), Columbia Gas Transmission Corp. (West Virginia and Pennsylvania), Cranberry Pipeline (West Virginia), Texas Eastern Pipeline (Pennsylvania), Transco Pipeline (Pennsylvania), Equitrans (West Virginia and Pennsylvania), Equitable Gas Company (West Virginia and Pennsylvania), and Carnegie Gas Company (West Virginia). The intrastate market outlets are Dominion Peoples (Pennsylvania), Dominion Hope (West Virginia), TW Phillips Oil & Gas Company, Inc. (Pennsylvania), Equitable Gas Company (West Virginia and Pennsylvania), Cabot Oil & Gas Corporation (West Virginia), Allegheny Power (West Virginia), National Fuel Gas Distribution (New York) and Lumberport Shinnston Gas Company (West Virginia).

We gather more than 90% of our current production. Our ownership and control of these lines enables us to:

- realize faster connection of newly drilled wells to the existing system;
- better control pipeline operating pressures and capacity to maximize our production;

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Item 1. Business and Properties - Continued

- control compression costs and fuel use;
- maintain system integrity;
- control the monthly nominations on the receiving pipelines to prevent imbalances and penalties; and
- closely track sales volumes and receipts to ensure all production values are realized.

Gathering for Others

We perform limited gas gathering activities for others on non-jurisdictional gathering, primarily in Pennsylvania. The fee charged to third party producers is set by contract and ranges from $0.10 to $0.44 per Mcf plus line loss and any compressor fuel. We aggregate these volumes with our production and sell all the gas through our meters to the same purchasers. These revenues are collected and distributed to the third party producers in the normal course of our revenue distribution cycle. Most of our gas gathering lines are not subject to United States Department of Transportation (US DOT) safety regulations.

Purchase for Resale

We own the Bessie 8 Pipeline in Pennsylvania and purchase and re-sell production from other producers connected to it. We intend to reconfigure other gas gathering systems to bring additional volumes online, both Company and third party owned, to the Bessie 8 Pipeline to increase throughput volumes and revenues.

Other Recent Developments

In October 2006, the Company completed a Class B Unit and Unit Purchase Agreement with a group of institutional investors whereby it privately placed 9,185,965 Class B units at a price of $20.55 per unit, and 5,534,687 units at a price of $21.00 per unit, for aggregate gross proceeds of $305.0 million (the Class B Private Placement). Proceeds, net of expenses of approximately $0.3 million, from the Class B Private Placement were used to repay indebtedness. In January 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of each of the Class B units into units.

In February 2007, the Company completed a Class C Unit and Unit Purchase Agreement with a group of institutional investors whereby it privately placed 7,465,946 Class C units at a price of $25.06 per unit and 6,650,144 units at a price of $26.00 per unit, for aggregate gross proceeds of $360.0 million, (the Class C Private Placement) which were used to finance the Stallion acquisition and the acquisitions of gas properties in West Virginia. See Note 4 in Notes to Consolidated Financial Statements for additional details about our private placements of our units.

Environmental Matters and Regulation

We believe that our properties and operations are in compliance with applicable environmental laws and regulations, and our operations to date have not resulted in any material environmental liabilities. To protect against potential environmental risk, we typically obtain Phase I environmental assessments of any properties to be acquired prior to completing each acquisition.

General. Our 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. Our 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 our operations; and

- with respect to operations affecting federal lands or leases, require preparation of a Resource Management Plan, an Environmental Assessment, and/or an Environmental Impact Statement.

These laws, rules and regulations may also restrict the rate of oil 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

Item 1. Business and Properties - Continued

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 our operating costs. We believe that we substantially comply with all current applicable environmental laws and regulations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict how future environmental laws and regulations may impact our properties or operations. For the year ended December 31, 2006, we did not incur any material capital expenditures for installation of remediation or pollution control equipment at any of our facilities. We are not aware of any environmental issues or claims that will require material capital expenditures during 2007 or that will otherwise have a material impact on our financial position or results of operations.

Environmental laws and regulations that have a material impact on the oil and gas industry include the following:

National Environmental Policy Act. Oil and gas production activities on federal lands are subject to the National Environmental Policy Act (NEPA). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will typically prepare an Environmental Assessment to assess the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current development and production activities, as well as proposed development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and gas projects.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act (RCRA), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and the disposal of non-hazardous wastes. Under the auspices of the Environmental Protection Agency (EPA), individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the development and production of oil, gas or geothermal energy constitute solid wastes, which are regulated under the less stringent non-hazardous waste provisions, but there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non-hazardous wastes or recategorize some non-hazardous wastes as hazardous for future regulation.

We believe that we are currently in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes as they are presently classified to be significant, any legislative or regulatory reclassification of oil and gas development and production wastes could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance at the site. Under CERCLA, such persons may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and gas development and production for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Federal Water Pollution Control Act. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls on the discharge of pollutants, including produced waters and other oil and gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the relevant state. The Clean Water Act also prohibits the discharge of

Item 1. Business and Properties - Continued

dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. We believe we are in substantial compliance with the requirements of the Clean Water Act.

Clean Air Act. The Clean Air Act, and associated state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Some of our new facilities may be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to comply with new emission limitations. These regulations may increase the costs of compliance for some facilities, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance. We believe that we are in substantial compliance with the requirements of the Clean Air Act.

Other Laws and Regulation. The Kyoto Protocol to the United Nations Framework Convention on Climate Change (the Protocol) became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, typically referred to as greenhouse gases that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has resisted recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Our operations are not adversely impacted by current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Other Regulation of the Oil and Gas Industry

The oil and gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, which frequently increases the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Legislation continues to be introduced in Congress and development of regulations continues in the Department of Homeland Security and other agencies concerning the security of industrial facilities, including oil and gas facilities. Our operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs we would incur to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;

- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing of units or proportion of units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate development while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state typically imposes a production or severance tax with respect to the production and sale of oil, gas and natural gas liquids within its jurisdiction.

Item 1. Business and Properties - Continued

Oil and Gas Transportation and Pricing. The availability, terms and cost of transportation significantly affect sales of oil and gas. The interstate transportation and sale of oil and gas are subject to federal regulation, primarily by the Federal Energy Regulatory Commission, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters. Federal and state regulations govern the price and terms for access to oil and gas pipeline transportation. The Federal Energy Regulatory Commission s regulations for interstate oil and gas transmission in some circumstances may also affect the intrastate transportation of oil and gas.

Although oil and gas prices are currently unregulated, Congress historically has been active in the area of oil and gas regulation. We cannot predict whether new legislation to regulate oil and gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties. Sales of condensate and oil and gas liquids are not currently regulated and occur at market prices.

State Regulation. The various states regulate the drilling for, and the production, gathering and sale of, oil and gas, including imposing severance 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 and gas that may be produced from our wells and to limit the number of wells or locations we 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. We do not believe that compliance with these laws will have a material adverse effect on our financial position or results of operations.

Item 1. Business and Properties - Continued

Executive Officers of the Company

Our executive officers as of February 28, 2007, were as follows:

Name	Age	Position with Our Company
Michael C. Linn	55	Chairman, President and Chief Executive Officer
Kolja Rockov	36	Executive Vice President and Chief Financial Officer
Mark E. Ellis	50	Executive Vice President and Chief Operating Officer
Lisa D. Anderson	45	Senior Vice President and Chief Accounting Officer
Roland Chip P. Keddie	54	Senior Vice President Administration and Secretary
Thomas A. Lopus	48	Senior Vice President Eastern Operations
Arden L. Walker, Jr.	47	Senior Vice President Western Operations
David J. Grecco	40	Vice President and General Counsel

Michael C. Linn is the Chairman, President and Chief Executive Officer of our Company and has served in such capacity since June 2006. Prior to that, from March 2003, he was the President, Chief Executive Officer and Director. From 2000 to 2003 Mr. Linn was President of Allegheny Interests, Inc., a private gas and oil 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 gas and oil company which 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 a member of the Independent Petroleum Association of America (IPAA), the largest national trade association of independent gas and oil producers. The members of the IPAA elected Mr. Linn to be the Chairman for the 2005 to 2007 term. He currently serves as a member of the Natural Gas Council and the National Petroleum Council and sits on the board of the Natural Gas Supply Association.

Kolja Rockov is the Executive Vice President and Chief Financial Officer of our Company. From October 2004 until he joined Linn 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.

Mark E. Ellis is the Executive Vice President and Chief Operating Officer of our Company and joined Linn in December 2006. From April 2006, until he joined Linn, Mr. Ellis served as President of the Lower 48 for ConocoPhillips Company. Prior to joining ConocoPhillips, from October 2004, Mr. Ellis served as Senior Vice President of North American Production for Burlington Resources. Prior to that, from November 2000, Mr. Ellis was President of Burlington Resources Canada Ltd. Mr. Ellis joined Burlington Resources in 1985 and began his career with The Superior Oil Company in 1979. Mr. Ellis is a member of the Society of Petroleum Engineers and a past board member of the New Mexico Oil & Gas Association. While in Calgary, he was a member of the Board of Governors of the Canadian Association of Petroleum Producers. 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.

Lisa D. Anderson is the Senior Vice President and Chief Accounting Officer of our Company. Ms. Anderson oversees the Company s accounting, financial reporting and internal control functions. Before joining Linn in July 2006, she was the Managing Director leading the Financial Reporting Risk Services practice for Protiviti. From January 2002 to August 2005, she served as a Managing Director with Jefferson Wells, and prior to 2002, she was an Assurance

Partner with KPMG LLP. Ms. Anderson 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.

Roland Chip P. Keddie is the Senior Vice President Administration and Secretary of our Company and has served in such capacity since April 2003. From January 2001 until April 2003, Mr. Keddie held the position of Project Landman with EOG Resources, Inc. and was responsible for various land services in the Appalachian Basin with a special emphasis on coal bed methane projects. Mr. Keddie formed Gateway Resources Management, LLC, a professional land services business, in October 1999 and was its sole member and President until January 2001. He currently serves as a board member of the

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Item 1. Business and Properties - Continued

Independent Oil and Gas Association of Pennsylvania and is a member of the American Association of Petroleum Landmen, the Independent Oil and Gas Association of New York, the Independent Oil and Gas Association of West Virginia and the Independent Petroleum Association of America.

Thomas A. Lopus is the Senior Vice President Eastern Operations. Mr. Lopus joined Linn in April 2006, as Senior Vice President Operations, to oversee the Company s drilling and production, engineering, land and geology operations. In February 2007, Mr. Lopus was appointed to his current position with responsibility for managing our existing assets in the Appalachian basin and any future assets we might acquire east of the Mississippi River. From March 2005 to March 2006, Mr. Lopus served as President of PNG Inc., a petroleum engineering consulting business. From February 2002 until March 2005, Mr. Lopus was Senior Vice President Operations of Equitable Resources, Inc. From February 2000 until February 2002, Mr. Lopus was Vice President of WELLOGIX, an energy software firm based in Houston.

Arden L. Walker, Jr. is the Senior Vice President Western Operations. Mr. Walker joined Linn in February 2007 to oversee our Western operations, which includes our California, Oklahoma and Texas assets. In addition, Mr. Walker will serve in the capacity of chief engineer for Linn, responsible for our future reserve review and booking processes. From April 2006 until he joined Linn, Mr. Walker served as Asset Development Manager, San Juan Business Unit for ConocoPhillips Company. Since June 2004, Mr. Walker served as General Manager, Asset Development in San Juan Division for Burlington Resources. Mr. Walker began his career with El Paso Exploration Company in 1982. Mr. Walker is a member of the Society of Petroleum Engineers and has served on the Board for Farmington Boys and Girls Club since 2004.

David J. Grecco is the Vice President and General Counsel of our Company and has served in such capacity since February 2006. Mr. Grecco joined our Company as General Counsel in December 2005. From September 1997 until October 2005, Mr. Grecco was employed as an attorney with the law firm Kirkpatrick & Lockhart Nicholson Graham LLP. Prior to that, Mr. Grecco was employed by Rockwell International Corporation from March 1993 through June 1996.

Item 1. Business and Properties - Continued

Employees

As of February 28, 2007, we employed approximately 220 personnel. We also contract for the services of independent consultants involved in land, regulatory, accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relationship with our employees is satisfactory.

Principal Executive Offices

We are a Delaware limited liability company with headquarters in Texas. Our principal executive offices are located at 600 Travis Street, Suite 7000, Houston, Texas 77002. Our main telephone number is (281) 605-4100.

Company Website

Our internet address is http://www.linnenergy.com. We make available free of charge on or through our website our 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 we electronically file such material with, or furnish it to, the SEC. Information on our 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 http://www.sec.gov. Any materials that we file 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 within the meaning of federal securities laws that are subject to a number of risks and uncertainties, many of which are beyond our control. These statements may include statements about our:

- business strategy;
- acquisition strategy;
- financial strategy;
- drilling locations;
- oil and gas reserves;
- realized oil and gas 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 our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties beyond our control. In addition, management s assumptions may prove to be inaccurate. We caution that the forward-looking statements contained in this Annual Report on Form 10-K are not guarantees of future performance, and we 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

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Item 1. Business and Properties - Continued

Annual Report on Form 10-K. The forward-looking statements speak only as of the date made, and other than as required by law, we undertake 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 the amount of 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:

- the amount of oil and gas we produce;
- the price at which we are able to sell our oil and gas production;
- the level of our operating costs;
- the level of our interest expense, which depends on the amount of our indebtedness and the interest payable thereon; and
- the 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:

- our ability to make working capital 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 will be prohibited from borrowing under our credit facility to pay distributions to unitholders if the amount of borrowings outstanding under our credit facility reaches or exceeds 90% of the borrowing base, which is the amount of money available for borrowing, as determined semi-annually by our lenders in their sole discretion. The lenders will redetermine the borrowing base based on an engineering report with respect to our oil and gas reserves, which will take into account the prevailing oil and gas prices at such time. Any time our borrowings exceed 90% of the then-specified borrowing base, our ability to pay distributions to our unitholders in any such quarter is solely dependent on our ability to generate sufficient cash from our operations.

If we do not make acquisitions on economically acceptable terms, then our future 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 pro forma available cash 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 pro forma available cash per unit, these acquisitions may nevertheless result in a decrease in pro forma available cash per unit.

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Item 1A. Risk Factors - Continued

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;
- mistaken assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- an inability to integrate successfully or timely the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management s attention from other business concerns;
- increased demands on existing personnel;
- customer or key employee losses at 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 distributions.

We have significant indebtedness under our credit facility. Our credit facility has 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. As of February 28, 2007, we had approximately $600.8 million outstanding under our credit facility (with additional borrowing capacity of approximately $120.2 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 our credit facility for future capital needs and to fund a portion of our distributions. The credit facility restricts 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 under our credit facility could result in a default under our credit facility, which could cause all of our existing indebtedness to be immediately due and payable.

Availability under our credit facility is determined semi-annually at the discretion of the lenders and is based in part on oil and gas 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. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other oil and gas 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 or gas 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 our business, results of operations, cash flows from operations and financial condition.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. All of the indebtedness outstanding under our credit facility is at variable interest rates, after giving effect to existing interest swap arrangements. Therefore, our business, results of operations and cash flows from operations could be adversely affected by significant increases in interest rates.

Item 1A. Risk Factors - Continued

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.

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 and gas. The oil and gas market is very volatile and a drop in prices can significantly affect our financial results and impede our growth. Changes in oil and gas prices have a significant impact on the value of our reserves and on our cash flow. Prices for oil and gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and gas, 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 and gas;
- 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 oil price and production controls;
- the impact of the U.S. dollar exchange rates on oil and gas prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of oil and gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

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

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

Declines in oil and gas 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 oil and gas 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 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 and gas 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 and gas 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.

Item 1A. Risk Factors - Continued

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 and gas in an exact way. Reserve engineering requires subjective estimates of underground accumulations of oil and gas and assumptions concerning future oil and gas 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. Over time, our internal engineers may make material changes to reserve estimates taking into account the results of actual drilling and production. 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 and gas 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 and gas 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 and gas 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 and gas 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 and gas;
- the amount and timing of actual production;
- supply of and demand for oil and gas; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use 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 and gas 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 and gas we are able to produce from existing wells;
- the prices at which we are able to sell our oil and gas; 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 and gas 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.

Item 1A. Risk Factors - Continued

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

Although we gather most of our current production, the marketability of our oil and gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems. The amount of oil and gas 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 the additional production. As a result, we may not be able to sell the oil and gas 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 and gas 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 and gas. To the extent these and other customers reduce the volumes of oil and gas they purchase from us, our revenues and cash available for distribution could decline.

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. For the year ended December 31, 2005, Dominion Resources, Inc., Cabot Oil & Gas Corporation and UGI Energy Services, Inc. accounted for approximately 48%, 14% and 10%, respectively, of our total volumes, or 72% in the aggregate. To the extent these and other customers reduce the volumes of oil or gas that they purchase from us, our revenues and cash available for distribution could decline.

We are exposed to the credit risk of our customers and certain parties, and a general increase in the nonpayment and nonperformance by our customers could have an adverse impact on our financial condition and results of operations.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. Any increase in the nonpayment and nonperformance by our customers could have an adverse impact on our operating results and could cause our cash available for distribution to decline.

Shortages of drilling rigs, pipe, equipment and crews could delay our operations and increase our drilling costs, which could impact our ability to generate sufficient cash flow from operations to pay quarterly distributions to our unitholders at the current distribution level.

Higher oil and gas prices increase the demand for drilling rigs, pipe, equipment and crews and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations which we currently have planned. Any delay in the drilling of new wells or significant increase in drilling costs could impact our ability to generate sufficient cash flow from operations to pay quarterly distributions to our unitholders at the current distribution level.

Because we handle oil and gas 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, and comparable state laws that impose requirements for the handling and disposal of waste from our facilities; and

Item 1A. Risk Factors - Continued

- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 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. See Part I. Item 1. Business and Properties - Operation - Environmental Matters and Regulation.

We may decide not to drill some of the prospects we have identified, and locations that we decide to drill may not yield oil and gas 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 seismic data processing and interpretation. Based on a variety of factors, including future oil and gas 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 and gas 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.

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 oil and gas 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, 2006, we had identified 1,254 drilling locations, of which 716 were proved undeveloped locations and 538 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 and gas prices, costs and drilling results. In addition, DeGolyer and MacNaughton has not assigned any proved reserves to the 538 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 and gas from these or any

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Item 1A. Risk Factors - Continued

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 and gas 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 and gas 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;
- 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 and gas or well fluids.

Any of these events can cause substantial losses, including 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.

Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and gas reserves. However, our reviews of acquired properties are inherently incomplete because it is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

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 and gas, we currently and may in the future enter into hedging arrangements for a significant portion of our oil and gas 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. Under our credit facility, we are prohibited from hedging all of our production, and we therefore retain the risk of a price decrease on our unhedged volumes.

Item 1A. Risk Factors - Continued

We depend on our Chairman, President and Chief Executive Officer who would be difficult to replace.

We depend on the performance of Michael C. Linn, our Chairman, President and Chief Executive Officer. We maintain no key person insurance for Mr. Linn. The loss of Mr. Linn could negatively impact our ability to execute our strategy and our results of operations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenue to allow us to pay distributions to our unitholders.

The oil and gas industry is intensely competitive, and we compete with companies that have greater resources than we have. Our ability to acquire additional properties and to discover reserves will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low oil and gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

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 and gas 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 oil and gas 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 - Operations - Environmental Matters and Regulation and Business - Operations - Other Regulation of the Oil and Gas Industry in this Annual Report on Form 10-K for a description of the laws and regulations that affect us.

If we fail to develop or 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 develop and 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 by our initial compliance date of December 31, 2007. We identified a material weakness in our internal controls during the course of evaluating disclosure controls and procedures as of December 31, 2005 and due to that material weakness, concluded our

Item 1A. Risk Factors - Continued

disclosure controls and procedures were not effective as of December 31, 2006. For additional information, see Part II. Item 9A. Controls and Procedures for additional information.

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.

We may face risks related to the restatement of our financial statements.

We restated our financial statements for the period from March 14, 2003 (inception) through December 31, 2003, for the year ended December 31, 2004 and certain financial statement line items for the nine months ended September 30, 2004 and 2005, primarily to correct certain accounting entries related to the acquisition of oil and gas properties. As a result of these changes, which primarily affected fiscal 2003 and 2004, revenues were reduced by $0.9 million and $1.7 million, respectively, and net loss was increased by $0.4 million and $83,018, respectively. Companies that restate their financial statements sometimes face litigation claims and/or SEC proceedings following such a restatement of financial results. Although we are unaware of any pending or threatened claims or proceedings relating to our restatement, if any claim or proceeding were to be commenced and successfully asserted against us, we could face monetary judgments, penalties or other sanctions which could adversely affect our financial condition and could cause the price of our units to decline.

Risks Related to Our Structure

Our management and Quantum Energy Partners own, in the aggregate, a significant interest in us, with management and Quantum Energy Partners owning approximately 11.1% and 20.2%, respectively, of our outstanding units.

Our management and Quantum Energy Partners own or control an aggregate 31.2% of our outstanding units without giving effect to the potential conversion of 7,465,946 non-voting Class C units into units. Post conversion of the Class C units, management and Quantum Energy Partners are expected to own or control approximately 9.6% and 17.6%, respectively, of our outstanding units. Accordingly, management and Quantum Energy Partners, acting together, possess significant voting power on substantially all matters submitted to a vote of the holders of our units. This concentration of ownership may have the effect of preventing or discouraging transactions involving an actual or a potential change of control of our company, regardless of whether a premium is offered over then-current market prices.

Each of management or Quantum Energy Partners, or both, may have conflicts of interest with us. 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 or Quantum Energy Partners on one hand, and the Company and our unitholders on the other hand. These potential conflicts may relate to the divergent interests of our management or Quantum Energy Partners. Situations in which the interests of our management or Quantum Energy Partners 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

- Quantum Energy Partners and other affiliates of our directors are not prohibited from investing or engaging in other businesses or activities that compete with us.

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

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

Item 1A. Risk Factors - Continued

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

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

The market price of our units could be volatile due to a number of factors, many of which are beyond our control.

The market price of our units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- changes in securities analysts recommendations and their estimates of our financial performance;
- the public s reaction to our press releases, announcements and our filings with the SEC;
- fluctuations in broader securities market prices and volumes, particularly among securities of oil and gas companies and securities of publicly-traded limited partnerships and limited liability companies;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other oil and gas companies;
- variations in the amount of our quarterly cash distributions;
- future issuances and sales of our units; and
- changes in general conditions in the U.S. economy, financial markets or the oil and gas industry.

In recent years, the securities market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our units.

Quantum Energy Partners and others may sell units in the future, which could reduce the market price of our outstanding units.

As of February 28, 2007, Quantum Energy Partners controlled an aggregate of 10,144,585 of our units. In addition, we have agreed, upon demand by Quantum Energy Partners, to register for sale units held by Quantum Energy Partners, certain non-affiliated investors and certain members of our management. These registration rights allow Quantum Energy Partners to request registration of their units and to include any of those units in a registration of other securities by us. If Quantum Energy Partners were to sell a substantial portion of their units, then the market price of our outstanding units may decline.

We also completed a private offering to institutional investors of 5,534,687 units and 9,185,965 newly created Class B units in October 2006, which were converted into units on a one-for-one basis in January 2007. We agreed to file a registration statement with the SEC covering the units and the units underlying the Class B units with the SEC. In accordance with the agreement, the registration statement must be declared effective by the SEC no later than 210 days following the closing (extended by separate agreement from 165 days).

In February 2007, we completed a private offering to institutional investors of 6,650,144 units and 7,465,946 Class C units. We agreed to file a registration statement with the SEC covering the units and the units underlying the Class C units with the SEC. In accordance with the agreement, the registration statement must be declared effective by the SEC no later than 165 days following the closing.

Each of our private placements discussed above were made without registration under the Securities Act of 1933, as amended (the Securities Act) in reliance on the exemption from the registration requirements for transactions not involving a public offering contained in Section 4(2) of the Securities Act.

If the institutional purchasers in the private placements discussed above were to sell a substantial portion of their units, then the market price of our outstanding units may decline.

Item 1A. Risk Factors - Continued

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.

Tax Risks to Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to 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 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 matters.

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 to unitholders would be taxed as corporate dividends, 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, our treatment as a corporation could result in a material reduction in the anticipated cash flow and after-tax return to our unitholders and therefore result in 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, 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. If any state were to impose a tax upon us as an entity, the cash available for distribution to unitholders may be reduced.

Our unitholders may be required to pay taxes on income from us 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.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter that affects us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

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

Because we cannot match transferors and transferees of units, we will adopt depreciation and amortization positions that may not conform with all aspects of existing U.S. Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or

Item 1A. Risk Factors - Continued

the amount of gain on the sale of units and could have a negative impact on the value of our units or result in audits of and adjustments to our unitholders tax returns.

Our unitholders may be subject to state and local taxes and return filing requirements.

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. We currently do business and own assets in West Virginia, Pennsylvania, New York, Virginia, California, Oklahoma, 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, foreign, 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 the units.

Tax gain or loss on the disposition of our units could be more or less than expected because prior distributions in excess of allocations of income will decrease the tax basis of the units.

As units are sold, our unitholders will recognize gain or loss equal to the difference between the amount realized and the tax basis in those units. Prior distributions to unitholders in excess of the total net taxable income they were allocated for a unit, which decreased our unitholders tax basis in that unit, will, in effect, become taxable income to them if the unit is sold at a price greater than their tax basis in that unit, even if the price received is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder.

We will be considered to have terminated for tax purposes due to a sale or exchange of 50% or more of our interests within a twelve-month period.

We will be considered to have terminated for tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. A constructive termination results in the closing of our taxable year for all unitholders and in the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, may result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31, will result in us filing two tax returns (and unitholders receiving two Schedule K-ls) for one fiscal year and the cost of the preparation of these returns will be borne by all of our unitholders.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

Our obligations under our credit facility are secured by mortgages on our oil and gas properties. See Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation - Credit Facility for additional information concerning our credit facility.

Offices

We currently lease approximately 44,000 square feet of office space in Houston, Texas at 600 Travis Street, where our principal offices are located, for which the lease expires in 2014. We also currently lease approximately 20,000 square feet of office space in Pittsburgh, Pennsylvania for which the lease expires in 2015. We own field offices in Brea, California, Glenville, West Virginia and Indiana, Pennsylvania.

Item 3. Legal Proceedings

Effective September 30, 2003, we purchased interests in oil and gas wells from Cabot Oil & Gas Corporation (Cabot) for an aggregate purchase price of $15.5 million. On September 27, 2005, Power Gas Marketing & Transmission Inc. (Power Gas) filed a complaint styled *Power Gas Marketing & Transmission, Inc. v. Cabot Oil & Gas Corporation and Linn Energy* in the court of common pleas of Indiana County, Pennsylvania against Cabot and Linn alleging that Cabot conveyed such interests to us in breach of purported preferential purchase rights. Power Gas alleges that we interfered with Power Gas contract rights and demands the right to evaluate whether to exercise its purported preferential purchase rights. We believe that Power Gas allegations are without merit, intend to vigorously defend the matter and do not believe that the outcome of the matter will have a material adverse effect on our financial position or results of operations.

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

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

No matters were submitted to a vote of security holders of the Company during the fourth quarter of the year ended December 31, 2006.

Part II

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

Market Information

Our units are listed on The NASDAQ Global Market under the symbol LINE and began trading on January 13, 2006, after pricing of our initial public offering.

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

Quarter Ended	Range of Sales Prices High		Low		Cash Distribution Declared Per Unit	
2006:						
First quarter	$	22.35	$	19.55	$	
Second quarter	$	21.00	$	18.72	$	0.32
Third quarter	$	24.10	$	20.08	$	0.40
Fourth quarter	$	33.46	$	21.21	$	0.43

Holders

As of February 27, 2007, there were approximately 10,186 holders of our units. In addition, there were approximately 44 holders of our unregistered Class C units. There is no established public trading market for our Class C units.

Distributions

Our limited liability company agreement requires us to make quarterly distributions to our 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 our Board of Directors to:

- provide for the proper conduct of our business (including reserves for future capital expenditures, future debt service requirements, and for our anticipated credit needs);
- comply with applicable law, any of our debt instruments or other agreements;
- provide funds for distribution to our unitholders;
- 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 our senior secured revolving 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 Results of Operation and Financial Condition - 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

Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes information regarding the number of our units that are available for issuance under all of our equity compensation plans as of December 31, 2006:

Plan category	**Number of securities to be issued upon exercise of outstanding unit options, warrants and rights**	**Weighted-average exercise price of outstanding unit options, warrants and rights**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))**
	(a)	(b)	(c)
Equity compensation plans approved by security holders	930,500	$ 24.24	1,844,810
Equity compensation plans not approved by security holders			
Total	930,500	$ 24.24	1,844,810

Cumulative Preferred Stock

The Company does not have any cumulative preferred stock outstanding.

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 Results of Operation and Financial Condition for discussion of these matters.

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

Unitholder Return Performance Presentation

The performance graph below compares the total unitholder return on our 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 our Company at the last reported sale price of our units as reported on The NASDAQ Global Market ($22.00) on January 13, 2006 (the day trading of our 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.

		1/13/2006			12/29/2006		
Linn Energy		$	100		$	153	(1)
Alerian MLP Index		$	100		$	120	
S&P 500 Index		$	100		$	112	

(1) Based on the last reported sale price of our units as reported on The NASDAQ Global Market on December 29, 2006 ($31.95).

Notwithstanding anything to the contrary set forth in any of our 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.

Item 6. Selected Financial Data

Set forth below is our selected historical consolidated financial data for the periods indicated for Linn (Successor). The historical financial data for the periods ended December 31, 2006, 2005, 2004 and 2003 and the balance sheet data as of December 31, 2006, 2005, 2004 and 2003 have been derived from our audited financial statements.

On August 1, 2006, we acquired certain affiliated entities of Blacksand, located in the Los Angeles Basin, for an aggregate purchase price, including estimated transaction costs and assumed liabilities, of approximately $301.0 million. On August 14, 2006, effective September 1, 2006, we acquired the Mid-Continent Kaiser-Francis Assets located in Oklahoma for an aggregate purchase price, including estimated transaction costs and assumed liabilities, of approximately $126.4 million. Linn results include Blacksand and the Kaiser-Francis Assets from the respective dates of acquisition in the tables below.

On October 31, 2003, we completed a $31.5 million acquisition of oil and gas assets from Waco Oil & Gas (Waco) (our Predecessor). The historical financial data for the period from January 1, 2003 through October 31, 2003 and the year ended December 31, 2002, have been derived from the audited financial statements of the Predecessor entity. The balance sheet data at December 31, 2002, has been derived from the unaudited financial statements of the Predecessor entity.

This selected financial data should be read in conjunction with Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation and the Consolidated Financial Statements and Notes thereto included elsewhere herein.

Because of our rapid growth through acquisitions and development of our properties, our historical results of operations and period-to-period comparisons of these results and certain other financial data may not be meaningful or indicative of future results.

The following tables present a non-GAAP financial measure, adjusted EBITDA, which we use in our business. This measure is not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain this measure below and reconcile it to the most directly comparable financial measure calculated and presented in accordance with GAAP in Non-GAAP Financial Measure beginning on page 51.

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Item 6. Selected Financial Data - Continued

	Successor			Period from March 14, 2003 (inception) - December 31, 2003	Predecessor Period from January 1, 2003 October 31, 2003	Year Ended December 31, 2002
	Year Ended December 31, 2006 (in thousands)	2005	2004		(in thousands)	
Statement of Operations Data:						
Revenues:						
Oil and gas sales	$ 80,393	$ 44,645	$ 19,502	$ 2,379	$ 4,705	$ 3,779
Gain (loss) on oil and gas derivatives (1) (2)	103,308	(76,193)	(11,004)	(1,437)		
Natural gas marketing revenues	5,598	4,722	520			
Other revenues	1,759	345	160	4	788	698
Total revenues	191,058	(26,481)	9,178	946	5,493	4,477
Expenses:						
Operating expenses	18,099	7,356	4,756	798	2,204	2,426
Natural gas marketing expenses	4,862	4,401	482			
General and administrative expenses (3)	39,993	3,332	1,488	783	870	1,047
Depreciation, depletion and amortization	24,173	7,294	3,656	562	1,185	1,494
Total expenses	87,127	22,383	10,382	2,143	4,259	4,967
Other income and (expenses):						
Interest income	761	47	7	34		
Interest expense, net of amounts capitalized (4)	(25,494)	(7,040)	(3,530)	(517)	(237)	(352)
Write-off of deferred financing fees and other losses	(3,415)	(420)	(89)	(8)	(14)	(208)
Total other income and (expenses)	(28,148)	(7,413)	(3,612)	(491)	(251)	(560)
Income (loss) before income taxes	75,783	(56,277)	(4,816)	(1,688)	983	(1,050)
Income tax (provision) (5)	3,402	(74)				
Income (loss) before cumulative effect of change in accounting principle	79,185	(56,351)	(4,816)	(1,688)	983	(1,050)
Cumulative effect of change in accounting principle					(757)	
Net income (loss)	$ 79,185	$ (56,351)	$ (4,816)	$ (1,688)	$ 226	$ (1,050)

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(1) During 2005, we canceled (before their original settlement date) a portion of out-of-the-money gas swaps and realized a loss of $38.3 million. We 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) The oil and gas derivatives are not designated as hedges under Statement of Financial Accounting Standards No. 133, *Accounting Derivatives and Hedging Activity* as amended, (SFAS 133) even though they reduce our exposure to changes in oil and gas prices. Therefore, the changes in fair value of these instruments were recorded in our current earnings. These amounts are non-cash gain or losses.

(3) The year ended December 31, 2006 includes non-cash unit-based compensation expense of $21.6 million, recorded in accordance with No. 123 (revised 2004), *Shared Based Payment.*

(4) Includes the unrealized gain (loss) on interest rate swaps that were not designated as hedges under SFAS 133, even though they reduce our exposure to changes in interest rates. Therefore, the changes in fair value of these instruments were recorded in our current earnings. These

amounts are non-cash gains or losses.

(5) Linn Operating, LLC was not subject to federal income tax before converting to a subchapter C-corporation on June 1, 2005. Prior to the conversion, there was no tax provision included in our consolidated financial statements because all of our taxable income or loss was included in the income tax returns of the individual members. The income tax benefit for the year ended December 31, 2006 was generated by the Company s taxable subsidiaries having net operating losses for the year. See Note 17 in Notes to Consolidated Financial Statements for additional details about the Company s income taxes.

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Item 6. Selected Financial Data - Continued

	Successor			Period from March 14, 2003 (inception) - December 31,	Predecessor Period from January 1, 2003 October 31,	Year Ended December 31,
	Year Ended December 31,					
	2006	2005	2004	2003	2003	2002
	(in thousands)				(in thousands)	
Cash Flow Data:						
Net cash provided by (used in) operating activities (1)	$ (6,805)	$ (29,518)	$ 10,351	$ (135)	$ 1,826	$ (40)
Net cash provided by (used in) investing activities	$ (551,631)	$ (150,898)	$ (61,373)	$ (35,344)	$ 10,880	$ (1,480)
Net cash provided by (used in) financing activities	$ 553,990	$ 189,269	$ 31,167	$ 57,521	$ (2,415)	$ 1,056
Capital expenditures	$ 551,737	$ 150,849	$ 63,594	$ 32,863	$ 1,717	$ 1,375
Other Financial Information (Unaudited):						
Adjusted EBITDA (2)	$ 75,084	$ 21,706	$ 11,298	$ 1,014	$	$

	Successor As of December 31, 2006	2005	2004	2003	Predecessor As of December 31, 2002 (Unaudited)	2001
	(in thousands)				(in thousands)	
Balance Sheet Data:						
Cash and cash equivalents (3)	$ 6,595	$ 11,041	$ 2,188	$ 22,043	$ 542	$ 1,006
Other current assets	63,081	23,692	5,892	1,971	710	447
Oil and gas properties, net of accumulated depreciation, depletion and amortization	733,289	239,293	95,381	52,307	12,829	12,831
Property, plant and equipment, net of accumulated depreciation	20,754	2,525	1,387	370	2,778	2,958
Other assets	92,589	4,373	577	2,486	168	208
Total assets	$ 916,308	$ 280,924	$ 105,425	$ 79,177	$ 17,027	$ 17,450
Current liabilities	$ 18,017	$ 86,557	$ 10,216	$ 20,200	$ 3,468	$ 3,498
Long-term debt	428,237	207,695	72,750	41,518	1,919	2,686
Other long-term liabilities	19,100	33,503	12,939	3,123		
Unitholders capital (deficit)	450,954	(46,831)	9,520	14,336	11,640	11,266
Total liabilities and unitholders capital	$ 916,308	$ 280,924	$ 105,425	$ 79,177	$ 17,027	$ 17,450

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(1) During 2005, we canceled (before their original settlement date) a portion of out-of-the-money gas hedges and

realized a loss of $38.3 million.

(2) See Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation - Non-GAAP Financial Measure.

(3) In December 2003, we borrowed approximately $18.0 million under our credit facility to pay the remaining purchase price for the Waco acquisition, which amount was paid to Waco in January 2004.

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Item 6. Selected Financial Data - Continued

Summary Reserve and Operating Data

The following tables show estimated net proved reserves, based on reserve reports prepared by DeGolyer and MacNaughton, our independent petroleum engineering firm for the year ended December 31, 2006, and certain summary unaudited information with respect to our production and sales of oil and gas. Schlumberger Data and Consulting Services provided the estimated reserves at December 31, 2005 and 2004. This data should be read in conjunction with Part I. Item 1. Business - Oil and Gas Data - Proved Reserves and Production and Price History, Part I. Item 1A. Risk Factors, and Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation.

	As of December 31,			
	2006	**2005**	**2004**	**2003**
Reserve Data:				
Estimated net proved reserves:				
Gas (Bcf)	274.0	191.9	118.9	68.9
Oil (MMBbls)	30.0	0.2	0.1	0.2
Proved developed (Bcfe)	314.1	125.2	74.4	41.8
Proved undeveloped (Bcfe)	140.0	68.0	45.4	28.0
Proved developed reserves as a % of total proved reserves	69.2%	64.8%	62.1%	59.9%
Standardized Measure (in millions) (1)	$ 552.3	$ 552.1	$ 215.0	$ 126.3
Representative Oil and Gas Prices:				
Gas NYMEX Henry Hub per MMBtu	$ 5.64	$ 10.08	$ 6.18	$ 5.97
Oil NYMEX West Texas Intermediate per Bbl	$ 61.05	$ 57.98	$ 43.36	$ 32.76

	Year Ended December 31,			
	2006	**2005**	**2004**	**Period from March 14, 2003 (inception) - December 31, 2003**
Production:				
Gas production (MMcf)	8,599	4,720	3,110	304
Oil production (MBbls)	370	20	10	1
Total production (MMcfe)	10,818	4,839	3,112	492
Average daily production (Mcfe/d)	29,638	13,258	8,526	2,299
Weighted Average Realized Prices: (2)				
Gas (Mcf)	$ 9.79	$ 6.92	$ 5.73	$ 5.26
Oil (Bbl) (3)	$ 58.68	$ 52.55	$ 37.83	$ 25.99
Total (Mcfe)	$ 9.79	$ 6.97	$ 5.74	$ 5.25
Average Unit Costs per Mcfe of Production (Non-GAAP):				
Operating expenses	$ 1.67	$ 1.52	$ 1.53	$ 1.62
General and administrative expenses (4)	$ 0.63	$ 0.69	$ 0.48	$ 1.59
Depreciation, depletion and amortization	$ 2.23	$ 1.51	$ 1.17	$ 1.14

(1) The Standardized Measure does not include future income tax expenses because our reserves are owned by our subsidiary Linn Energy Holdings, LLC, which is not subject to income taxes. The Standardized Measure does not

give effect to derivative transactions. For a description of our derivative transactions, see Part II. Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation - Statements of Cash Flows.

(2) Includes the effect of realized gains and losses on oil and gas derivatives.

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

(4) This is a non-GAAP performance measure used by our management and is a quantitative measure used in the oil and gas industry. The measure for the year ended December 31, 2006 excludes approximately $21.6 million of unit-based compensation expense and $2.0 million of bonuses paid to certain executive officers in connection with our IPO. General and administrative expenses including these amounts was $3.70 per Mcfe for the year ended December 31, 2006.

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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 our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our 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 and gas, 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.

Executive Summary

We are an independent oil and gas company focused on the development and acquisition of long-lived properties in the United States. Our Company was formed in March 2003 and in January 2006, we completed our IPO of 12,450,000 units at a price of $21.00 per unit, for net proceeds after underwriting discounts and offering expenses of $238.8 million (see Statements of Cash Flows Financing Activities below for additional details). In October 2006, the Company privately placed 9,185,965 Class B units at a price of $20.55 per unit, and 5,534,687 units at a price of $21.00 per unit, or a total of 14,720,652 units at a blended price of $20.72 per unit, for aggregate gross proceeds of $305.0 million. Proceeds, net of expenses of approximately $0.3 million, from the Class B Private Placement were used to repay indebtedness. The Class B units were subsequently converted into units on a one-for-one basis per unitholder vote in January 2007. In February 2007, the Company privately placed 7,465,946 Class C units at a price of $25.06 per unit and 6,650,144 units at a price of $26.00 per unit, or a total of 14,116,090 units at a blended price of $25.50 per unit, for aggregate gross proceeds of approximately $360.0 million, which were used to partially finance the Stallion acquisition and the acquisition of certain gas properties in West Virginia (see Note 2 in Notes to Consolidated Financial Statements). See Private Placement Class B Units and Private Placement Class C Units in Liquidity and Capital Resources below for additional details.

Our goal is to provide stability and growth in distributions to our unitholders through continued successful drilling and, acquisitions, increasing production of existing wells and pursuing operational and administrative efficiencies. Our properties and our oil and gas reserves are currently located in four core areas:

- Appalachian Basin, which includes West Virginia, Pennsylvania, New York and Virginia;
- Western, which includes the Brea Olinda Field of the Los Angeles Basin in California;
- Mid-Continent, which includes the Sooner Trend of north central Oklahoma; and
- Texas Panhandle, which includes the Texas portion of the Hugoton-Panhandle Field.

During the year ended December 31, 2006, we completed five acquisitions of oil and gas properties and related gathering and pipeline assets for an aggregate purchase price of approximately $454.9 million, with total proved reserves of 263.7 Bcfe, or an acquisition cost of approximately $1.72 per Mcfe. As of December 31, 2006, since inception, we completed 14 acquisitions of oil and gas properties and related gathering and pipeline assets for an aggregate purchase price of approximately $656.4 million, with total proved reserves of approximately 441.5 Bcfe, or an acquisition cost of approximately $1.49 per Mcfe. As part of our business strategy, we continually evaluate opportunities to acquire additional oil and gas properties that complement our asset profile. See Acquisitions below for details about our most recent acquisitions in Texas and West Virginia, which are not included in our reserves at December 31, 2006.

Our proved reserves at December 31, 2006, which exclude our three acquisitions in the first quarter of 2007, were 454.1 Bcfe, of which approximately 60.3% were gas and 39.7% were oil. Approximately 69.2% were classified as proved developed, with a total proved Standardized Measure value of $552.3 million. At December 31, 2005, we had 193.2 Bcfe of estimated net proved reserves with a Standardized Measure of $552.1 million. Our December 31, 2006 and 2005 Standardized Measures were determined using a price of $5.64 and $10.08 per Mcf of gas, respectively, and $61.05 and $57.98 per Bbl of oil, respectively. Our production was approximately 79.5% gas and 20.5% oil for the year ended December 31, 2006. During 2005, oil accounted for less than 3% of our production.

At December 31, 2006, we operated 2,683, or 73.3%, of our 3,659 productive wells. Our average proved reserves-to-production ratio, or average reserve life, is approximately 29.5 years, based on our December 31, 2006 reserve report and annualized production for the fourth quarter ended December 31, 2006.

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

Acquisitions

The Company made two significant acquisitions in the third quarter of 2006. The Company acquired certain affiliated entities of Blacksand, located in the Los Angeles Basin, for an aggregate purchase price of approximately $301.0 million and certain Mid-Continent Kaiser-Francis Assets, located in Oklahoma, for an aggregate purchase price of approximately $126.4 million. Results of Blacksand and the Kaiser-Francis Assets are included in the consolidated results of the Company beginning August 1, 2006 and September 1, 2006, respectively. See Note 2 in Notes to Consolidated Financial Statements for further details about the Blacksand and Kaiser-Francis acquisitions. The following table provides a summary of the oil and gas properties we have acquired from inception through the date of this report:

Year	# of Acquisitions	Gross Wells	Location	Aggregate Contract Price
				(in millions)
2003	4	498	West Virginia, Virginia, New York and Pennsylvania	$52.0
2004	2	698	Pennsylvania	25.9
2005	3	718	West Virginia and Virginia	124.5
2006	5	1,430	West Virginia, California and Oklahoma	451.7
2007	3	902	West Virginia and Texas	453.9
	17	4,246		$1,108.0

Our acquisitions were financed with a combination of private placements of our units, proceeds from bank borrowings and cash flow from operations. Our activities are focused on evaluating and developing our asset base, increasing our acreage positions and evaluating potential acquisitions. Because of our rapid growth through acquisitions and development of our properties, our historical results of operations and period-to-period comparisons of these results and certain financial data may not be meaningful or indicative of future results.

In February 2007, the Company completed the acquisition of certain oil and gas properties and related assets in the Texas Panhandle from Cavallo Energy, LP, acting through its general partner, Stallion for a contract price of $415.0 million, subject to customary post-closing adjustments (see Note 2 in Notes to Consolidated Financial Statements for additional details). In addition, in January 2007, the Company completed two acquisitions of certain gas properties located in the Appalachian Basin of West Virginia for an aggregate contract price of $39.0 million, subject to customary post-closing adjustments. In connection with these acquisitions, the Company amended its credit facility to increase the borrowing base from $480.0 million to $725.0 million. See Credit Facility below for additional details.

Drilling

The following table sets forth information, as of December 31, 2006, relating to our drilling locations and net acres of leasehold interests in each of our three core areas.

	Appalachian Basin	Western	Mid-Continent	Total
Proved undeveloped	581	2	133	716
Other locations	538			538
Total drilling locations	1,119	2	133	1,254
Leasehold interests-net acres	174,000	810	53,896	228,706

We utilize the successful efforts method of accounting for our oil and gas properties. Leasehold costs are capitalized when incurred. Unproved properties are assessed periodically within specific geographic areas and impairments are charged to expense. Geological and geophysical expenses and delay rentals are charged to expense as incurred. Drilling costs are capitalized, but charged to expense if the well is determined to be unsuccessful. We carry the costs of an exploratory well as an asset if the well finds a sufficient quantity of reserves to justify its capitalization as a producing well as long as we are making sufficient progress assessing the reserves and the economic and operating viability of the project.

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

Higher oil and gas prices have led to higher demand for drilling rigs, operating personnel and field supplies and services and have caused increases in the costs of those goods and services. The Company performs certain activities in connection with its drilling of oil and gas wells, which includes preparing and clearing well sites, providing drilling engineers, roustabouts and other personnel necessary for drilling. During 2006, the Company took delivery of its first two drilling rigs, with an additional rig delivered in the first quarter of 2007, which will reduce reliance on contract rigs. In the third quarter of 2006, the Company began, for the first time, operating its own drilling rigs staffed with Company personnel. Given the inherent volatility of oil and gas prices, which are influenced by many factors beyond our control, we plan our activities and budget based on conservative sales price assumptions, which are lower than the average sales prices ultimately realized. We focus our efforts on increasing oil and gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future cash flow from operations is dependent on our ability to manage our overall cost structure.

We face the challenge of natural production declines. As initial reservoir pressures are depleted, oil or gas production from a given well decreases. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus on adding reserves through drilling and acquisitions as well as the costs necessary to produce such reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals.

Operations

Our revenues are highly sensitive to changes in oil and gas prices and levels of production. As of December 31, 2006, we have hedged a significant portion of our expected production through 2011 using oil and gas derivatives, which allows us to mitigate, but not eliminate, commodity price risk. Our expected increase in levels of production as a result of the anticipated drilling of over 250 wells during 2007 is dependent on our ability to quickly and efficiently bring the newly drilled wells online. Any delays in drilling, completion or connection to gathering lines of our new wells will negatively impact the rate of increase in our production, which may have an adverse effect on our revenues and as a result, cash available for distribution. We continuously conduct financial sensitivity analyses to assess the effect of changes in pricing and production. These analyses allow us to determine how changes in oil and gas prices will affect the ability to drill additional wells and to meet future financial obligations. Further, the financial analyses allow us to monitor any impact such changes in oil and gas prices may have on the value of our proved reserves and their impact, if any, on any redetermination of the borrowing base under our credit facility.

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other producers. Oil and gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas reserves that we can economically produce and our access to capital.

Production and Operating Costs Reporting

We strive to increase our production levels to maximize our revenue and cash available for distribution. Additionally, we continuously monitor our operations to ensure that we are incurring operating costs at the lowest possible level. Accordingly, we analyze our production and operating costs per well to determine if any wells should be shut in or sold.

Land and Lease Tracking System

As a significant amount of our growth is dependent on drilling new wells, we continuously monitor our lease agreements and our drilling locations to avoid delays. Our monitoring system matches our lease agreements to existing wells and sites for future development, allowing management to make real time decisions on which acreage to develop and at what point in time. We continually seek to acquire new lease positions to increase potential drilling locations.

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 tables set forth selected financial and operating data for the years indicated:

	Year Ended December 31, 2006 (in thousands)	2005	Variance
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):			
Interest expense, net of amounts capitalized	$ (25,494)	$ (7,040)	$ (18,454)

	Year Ended December 31, 2006	2005	Percentage Increase (Decrease)
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 (Mcfe/d)	29,638	13,258	123.5 %
Weighted Average Realized Prices: (2)			
Gas (Mcf)	$ 9.79	$ 6.92	41.5 %
Oil (Bbl) (3)	$ 58.68	$ 52.55	11.7 %
Total (Mcfe)	$ 9.79	$ 6.97	40.5 %
Average Unit Costs per Mcfe of Production (Non-GAAP):			
Operating expenses	$ 1.67	$ 1.52	9.9 %
General and administrative expenses (4)	$ 0.63	$ 0.69	(8.7)%
Depreciation, depletion and amortization	$ 2.23	$ 1.51	47.7 %

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

(2) Includes the effect of realized gains of $25.5 million and realized losses of $13.1 million (excludes the $38.3 million loss noted above) on oil and gas derivatives for the years ended December 31, 2006 and 2005, respectively.

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

(4) This is a non-GAAP performance measure used by our management and is a quantitative measure used in the oil and gas industry. The measure for the year ended December 31, 2006 excludes approximately $21.6 million of unit-based compensation expense and $2.0 million of bonuses paid to certain executive officers in connection with our IPO. General and administrative expenses including these amounts was $3.70 per Mcfe for the year ended December 31, 2006.

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, we entered into commodity pricing derivative contracts for approximately 108% of our gas production and 50% of our oil production, which resulted in revenues that were $25.5 million greater than we would have achieved at unhedged prices. During the year ended December 31, 2005, we entered into commodity pricing derivative contracts for approximately 84% of our oil and gas production, which resulted in revenues that were $13.1 million less than we would have achieved at unhedged prices. During the year ended December 31, 2005, we canceled (before their 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 consist of lease operating expenses, labor, field office rent, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, severance and ad valorem taxes and other customary charges. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. We assess our operating expenses by monitoring the expenses in relation to the amount of production and the number of wells operated. 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, we have drilled 359 wells and acquired 3,344 wells.

General and administrative expenses include the costs of our employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. We monitor general and administrative expenses in relation to the amount of production and the number of wells operated. 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 our rapidly growing operations and position the Company for future growth include increasing our 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 our 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.

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 in the Blacksand and Kaiser-Francis acquisitions in the third quarter of 2006. In addition, the depletion rate for our oil and gas properties in the Appalachia Basin increased 37.4% in the fourth quarter of 2006, due to a downward revision of our estimated reserves from the prior year. The Company also recorded $1.0 million of impairments during the year ended December 31, 2006. During the years ended December 31, 2006 and 2005, the Company capitalized approximately

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

$8.5 million and $1.6 million, respectively, of costs related to drilling for specific activities related to drilling its wells, which included site preparation, drilling labor, meter installation, pipeline connection and site reclamation. Capitalized drilling costs increased compared to the prior year due to the Company s purchase and placement of its own drilling rigs into service during the third quarter of 2006. The Company began, for the first time, operating its own drilling rigs, staffed with Company personnel. Company personnel also perform activities using leased equipment, and did so prior to the purchase of its own rigs. The aggregate amount spent on drilling and development for the years ended December 31, 2006 and 2005 was approximately $47.0 million and $27.1 million, respectively.

Interest and financing income (expense) increased to a net expense of $25.5 million for the year ended December 31, 2006, compared to a net expense of $7.0 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. Our interest rate swaps were not designated as hedges under SFAS 133, even though they reduce our 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 is an LLC, 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. Management has determined such losses will be 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.

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

Results of Operations - Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

The following tables set forth selected financial and operating data for the years indicated:

	Year Ended December 31, 2005 (in thousands)	2004	Variance
Revenues:			
Gas sales	$ 43,594	$ 19,129	$ 24,465
Oil sales	1,051	373	678
Total oil and gas sales	44,645	19,502	25,143
Loss on oil and gas derivatives (1)	(76,193)	(11,004)	(65,189)
Natural gas marketing revenues	4,722	520	4,202
Other revenues	345	160	185
Total revenue	$ (26,481)	$ 9,178	$ (35,659)
Expenses:			
Operating expenses	$ 7,356	$ 4,756	$ 2,600
Natural gas marketing expenses	4,401	482	3,919
General and administrative expenses	3,332	1,488	1,844
Depreciation, depletion and amortization	7,294	3,656	3,638
Total expenses	$ 22,383	$ 10,382	$ 12,001
Other Income and (Expenses):			
Interest expense, net of amounts capitalized	$ (7,040)	$ (3,530)	$ (3,510)

	Year Ended December 31, 2005	2004	Percentage Increase (Decrease)
Production:			
Gas production (MMcf)	4,720	3,502	54.7 %
Oil production (MBbls)	20	10	100.0 %
Total production (MMcfe)	4,839	3,112	55.5 %
Average daily production (Mcfe/d)	13,258	8,526	55.5 %
Weighted Average Realized Prices: (2)			
Gas (Mcf)	$ 6.92	$ 5.73	20.8 %
Oil (Bbl)	$ 52.55	$ 37.83	38.9 %
Total (Mcfe)	$ 6.97	$ 5.74	21.4 %
Average Unit Costs per Mcfe of Production (Non-GAAP):			
Operating expenses	$ 1.52	$ 1.53	(0.7)%
General and administrative expenses	$ 0.69	$ 0.48	43.8 %
Depreciation, depletion and amortization	$ 1.51	$ 1.17	29.1 %

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

(2) Includes the effect of realized losses of $13.1 million (excludes the $38.3 million loss noted above) and $2.2 million on oil and gas derivatives for the years ended December 31, 2005 and 2004, respectively.

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

Revenues

Oil and gas sales increased to approximately $44.6 million for the year ended December 31, 2005, from $19.5 million for the year ended December 31, 2004.

The increase in revenue from oil and gas sales was attributable primarily to increased production. Total production increased to 4,839 MMcfe during the year ended December 31, 2005, from 3,112 MMcfe during the year ended December 31, 2004, due to the drilling of new wells and production added by the acquisitions of oil and gas properties during 2005 and 2004. The Company drilled 110 wells during 2005 compared to 90 wells in 2004. In addition to the increase in production, the average gas sales price increased during the year ended December 31, 2005 compared to the year ended December 31, 2004.

Hedging Activities

During the year ended December 31, 2005, we entered into commodity pricing derivative contracts for approximately 84% of our oil and gas production, which resulted in revenues that were $13.1 million less than we would have achieved at unhedged prices. During the year ended December 31, 2004, we entered into commodity pricing derivative contracts for approximately 72% of our oil and gas production, which resulted in revenues that were $2.2 million less than we would have achieved at unhedged prices. During the year ended December 31, 2005, we canceled (before their 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 losses on derivatives in the amounts of $24.8 million and $8.8 million in 2005 and 2004, respectively, were also recorded. Unrealized losses result from oil and gas price fluctuations as compared to the settlement price on the derivative.

Expenses

Operating expenses consist of lease operating expenses, labor, field office rent, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies, severance and ad valorem taxes and other customary charges. Severance taxes are a function of volumes and revenues generated from production. Ad valorem taxes vary by state/county and are based on the value of our reserves. We assess our operating expenses by monitoring the expenses in relation to the amount of production and the number of wells operated. Operating expenses increased to $7.4 million for the year ended December 31, 2005, from $4.8 million for the year ended December 31, 2004, due to the increase in the number of producing wells as a result of the acquisitions completed in both 2005 and 2004 and the drilling of 110 wells during 2005 and 90 wells during 2004.

General and administrative expenses include the costs of our employees and executive officers, related benefits, office leases, professional fees and other costs not directly associated with field operations. We monitor general and administrative expenses in relation to the amount of production and the number of wells operated. General and administrative expenses increased to $3.3 million for the year ended December 31, 2005, from $1.5 million for the year ended December 31, 2004. General and administrative expenses are presented net of approximately $1.2 million and $0.6 million during the years ended December 31, 2005 and 2004, respectively, which represent expense reimbursements from other working interest owners. 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 due diligence for acquisitions that did not reach fruition, contributed to the increase. Costs to support our rapidly growing operations, including increasing our staffing level to manage the additional wells acquired and drilled in 2005 and 2004, and to perform the functions associated with preparation to become a public company also contributed to the increase.

Depreciation, depletion and amortization increased to $7.3 million for the year ended December 31, 2005, from $3.7 million for the year ended December 31, 2004, due to the increase in the number of wells as a result of the acquisitions completed and the wells drilled in 2005 and 2004, as noted above. Additionally, during the years ended December 31, 2005 and 2004, the Company capitalized approximately $1.6 million and $0.2 million, respectively, of costs related to drilling.

Interest and financing income (expense) increased to a net expense of $7.0 million for the year ended December 31, 2005, compared to a net expense of $3.5 million for the year ended December 31, 2004, primarily due to increased debt levels associated with acquisitions and drilling. Cash payments for interest increased to $6.5 million for the year ended December 31, 2005, from $2.0 million for the year ended December 31, 2004. Our interest rate swaps were not designated as hedges under SFAS 133, even though they reduce our exposure to changes in interest rates. Therefore, the changes in fair values of these instruments were recorded as a gain of $1.0 million and a loss of approximately $1.3 million for the years ended December 31, 2005 and 2004, respectively. These amounts are non-cash gains and losses.

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

Income tax expense was approximately $74,000 for the year ended December 31, 2005, compared to $0 in 2004. Linn is an LLC, and is taxed substantially as a partnership.

Liquidity and Capital Resources

We utilize private placements of our units, proceeds from bank borrowings and cash flow from operations for our capital resources and liquidity. To date, our primary use of capital has been for the acquisition and development of oil and gas properties. As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations and planned capital expenditures. Our future success in growing reserves and production will be highly dependent on the capital resources available to us and our success in drilling for or acquiring additional reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our credit facility, if available, or obtain additional debt or equity financing. Our credit facility imposes certain restrictions on our ability to obtain additional debt financing. Based upon our current expectations, we believe our liquidity and capital resources will be sufficient for the conduct of our business and operations.

Statements of Cash Flows Operating Activities

At December 31, 2006, we had cash and cash equivalents of $6.6 million compared to $11.0 million at December 31, 2005.

Cash used in operating activities was $ 6.8 million and $29.5 million for the years ended December 31, 2006 and 2005, respectively. The decrease in cash used by operating activities was due to the increase in net income, which was $78.2 million for the year ended December 31, 2006, compared to a net loss of $56.4 million for the year ended December 31, 2005. See Results of Operations above for detail about the increase in components of net income. In addition, the Company paid premiums of approximately $49.8 million for its oil and gas derivatives, which is reported as a use of operating cash.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil and gas prices. Oil and gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on our ability to maintain and increase production through our drilling program and acquisitions, as well as the prices of oil and gas.

We enter into derivative arrangements to reduce the impact of oil and gas volatility on our operations. Currently, we use fixed price swaps and puts to reduce our exposure to the volatility in oil and gas prices.

By removing the price volatility from a significant portion of our oil and gas production, we have mitigated, but not eliminated, the potential effects of changing prices on our cash flow from operations for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices. It is our policy to enter into derivative contracts only with counterparties that are major, creditworthy financial institutions deemed by management as competent and competitive market makers.

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

The following tables summarize, as of February 28, 2007, and for the periods indicated, our derivatives in place through December 31, 2011. Currently, we use fixed price swaps and puts to manage commodity prices. The gas transactions are settled based upon the closing NYMEX future price of gas on the settlement date, which occurs on the third day of the production month proceeding the production month. The oil transactions are settled based upon the average daily NYMEX price of light oil and settlement occurs on the final day of the production month.

	March 1-December 31, 2007	Year 2008	Year 2009	Year 2010	Year 2011
Gas Positions					
Fixed Price Swaps:					
Hedged Volume (MMBtu)	6,673	10,264	10,405	8,520	7,800
Average Price ($/MMBtu)	$ 8.73	$ 8.37	$ 7.73	$ 7.20	$ 7.20
Puts:					
Hedged Volume (MMBtu)	7,250	7,053	6,960	6,960	6,960
Average Price ($/MMBtu)	$ 8.18	$ 8.07	$ 7.50	$ 7.50	$ 7.50
Total:					
Hedged Volume (MMBtu)	13,923	17,317	17,365	15,480	14,760
Average Price ($/MMBtu)	$ 8.44	$ 8.25	$ 7.64	$ 7.34	$ 7.34

	March 1-December 31, 2007	Year 2008	Year 2009	Year 2010	Year 2011
Oil Positions					
Fixed Price Swaps:					
Hedged Volume (MBbls)	417	560	580	550	525
Average Price ($/Bbl)	$ 75.83	$ 74.31	$ 73.87	$ 74.54	$ 61.58
Puts:					
Hedged Volume (MBbls)	1,250	1,550	1,550	1,700	1,750
Average Price ($/Bbl)	$ 66.33	$ 66.29	$ 66.29	$ 66.18	$ 65.00
Total:					
Hedged Volume (MBbls)	1,667	2,110	2,130	2,250	2,275
Average Price ($/Bbl)	$ 68.71	$ 68.42	$ 68.35	$ 68.22	$ 64.21

The oil and gas derivatives are not designated as cash flow hedges under SFAS 133 and, accordingly, the changes in fair value are recorded in current period earnings.

Statements of Cash Flows Investing Activities

Cash used in investing activities was $551.6 million for the year ended December 31, 2006, compared to $150.9 million for the year ended December 31, 2005. The increase in cash used in investing activities was due primarily to the acquisitions of Blacksand and the Kaiser-Francis Assets in the third quarter of 2006, as well as to several other acquisitions that were completed in the second quarter of 2006. See Note 2 in Notes to Consolidated Financial Statements.

The total cash used in investing activities for the year ended December 31, 2006 includes $298.1 million and $125.0 million for the acquisitions of Blacksand and the Kaiser-Francis Assets, respectively. Other acquisitions and additional working interests in our current wells were approximately $46.2 million and property, plant and equipment purchases accounted for $15.4 million. In December 20006, we also made a deposit of $20.0 million for the February 2007 acquisition of Stallion (see Note 2 in Notes to Consolidated Financial Statements). The total for the year ended December 31, 2006 also includes $47.0 million for the drilling and development of oil and gas properties.

The total for the year ended December 31, 2005 includes $111.4 million for the acquisition of Exploration Partners, LLC, $11.2 million for the acquisition of other oil and gas properties and wells and additional working interests in our current wells and $1.6 million for property, plant and equipment. It also includes $27.1 million for the drilling and development of oil and gas properties.

We currently anticipate that our drilling budget, which predominantly consists of drilling, infrastructure projects and equipment, will be between $80.0 million and $120.0 million for 2007. At February 28, 2007, we had $120.2 million available for

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

borrowing under our credit facility. The amount and timing of our capital expenditures is largely discretionary and within our control. If oil and gas prices decline below acceptable levels, we could choose to defer a portion of our planned capital expenditures until later periods. We routinely monitor and adjust our capital expenditures in response to changes in oil and gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and crews. Based upon current oil and gas price expectations for 2007, we anticipate that our cash flow from operations and available borrowing capacity under our credit facility will exceed our planned capital expenditures and other cash requirements for 2007. However, future cash flows are subject to a number of variables, including the level of gas production and prices. There can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Statements of Cash Flows Financing Activities

Cash provided by financing activities was $554.0 million for year ended December 31, 2006, compared to $189.3 million for the year ended December 31, 2005. In the first quarter of 2006, we completed our IPO of an aggregate of 12,450,000 units representing limited liability company interests at $21.00 per unit. The gross proceeds received in the IPO were $261.4 million. Net proceeds to the Company (after underwriting discounts of approximately $18.3 million) were approximately $243.1 million, of which $122.0 million was used to reduce the Company s then-existing indebtedness, approximately $114.4 million was used to redeem a portion of the membership interests in the Company and units held by certain affiliated and non-affiliated holders, approximately $4.3 million was used to pay offering expenses and approximately $2.0 million was used to pay bonuses to certain executive officers of the Company.

The Company also recorded gross proceeds of $305.0 million from a private placement of its units during 2006 (see Private Placement Class B Units below). The proceeds, net of expenses of approximately $0.3 million, were used to repay in full the Company s $250.0 million Subordinated Bridge Loan and $53.3 million of borrowings under its Credit Facility. Total payments made on the Credit Facility during 2006 were $115.3 million.

During 2006, the Company received proceeds from borrowings on its Credit Facility of $334.0 million, and from borrowing on its Subordinated Bridge Loan of $250.0 million. These proceeds were used primarily to fund the acquisitions of Blacksand and the Kaiser-Francis Assets.

In April 2006, the Company s Board of Directors declared a distribution of $0.32 per unit with respect to the first quarter of 2006 pro-rated for the period from the closing of the IPO on January 19, 2006 to March 31, 2006. As a result, the Company paid aggregate distributions of approximately $8.9 million in May 2006.

In July 2006, the Company s Board of Directors declared a distribution of $0.40 per unit with respect to the second quarter of 2006. The distribution totaling approximately $11.2 million was paid in August 2006.

In October 2006, the Company s Board of Directors declared a distribution of $0.43 per unit with respect to the third quarter of 2006. The distribution totaling approximately $12.0 million was paid in November 2006.

In January 2007, the Company s Board of Directors declared a distribution of $0.52 per unit with respect to the fourth quarter of 2006. The distribution totaling approximately $22.5 million was paid in February 2007 to unitholders of record at the close of business on January 29, 2007.

Company management currently anticipates recommending to the Board of Directors an increase in the cash distribution beginning with the second fiscal quarter of 2007 to an annual rate of $2.28 per unit from the current annual rate of $2.08 per unit.

Private Placement Class B Units

In October 2006, the Company completed a Class B Unit and Unit Purchase Agreement with a group of institutional investors whereby it privately placed 9,185,965 Class B units at a price of $20.55 per unit, and 5,534,687 units at a price of $21.00 per unit, for aggregate gross proceeds of $305.0 million, with offering expenses of approximately $0.3 million, (the Class B Private Placement). In January 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of each of the Class B units into units. In connection with the Class B Private Placement, the Company also agreed to file a registration statement with the SEC covering the units and the units underlying the Class B units. In accordance with the

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

agreement, the registration statement must be declared effective by the SEC no later than 210 days following the closing (extended by separate agreement from 165 days).

As noted above, proceeds from this transaction were used to repay indebtedness. In connection with the repayment of the subordinated bridge loan, the Company wrote off approximately $2.7 million of deferred financing fees, which was recognized as expense in the fourth quarter of 2006.

Private Placement Class C Units

In February 2007, the Company completed a Class C Unit and Unit Purchase Agreement with a group of institutional investors whereby it privately placed 7,465,946 Class C units at a price of $25.06 per unit, and 6,650,144 units at a price of $26.00 per unit, for aggregate gross proceeds of $360.0 million (the Class C Private Placement). The proceeds from the Class C Private Placement were used to finance the Stallion acquisition and the acquisitions of certain gas properties in West Virginia (see Note 2 in Notes to Consolidated Financial Statements).

The Class C units represent a new class of equity securities that is entitled to a special quarterly distribution equal to 115% of the distribution received by the existing units. The Class C units have no voting rights other than as required by law and are subordinated to the units on dissolution and liquidation. If approved by a vote of the Company s unitholders at the special meeting to be held in April 2007, the Class C units will convert to units on a one-for-one basis. In connection with the Class C Private Placement, the Company also agreed to file a registration statement with the SEC covering the units and the units underlying the Class C units. In accordance with the agreement, the registration statement must be declared effective by the SEC no later than 165 days following the closing.

The Company has agreed to file a registration statement to register the future resale of units issued under the Class B Private Placement and the Class C Private Placement shortly after the filing of its Annual Report on Form 10-K. Under the terms of the Class B Private Placement and the Class C Private Placement, if the registration statements are not declared effective in accordance with the respective agreements, the Company could be required to pay purchasers, as liquidated damages and not as a penalty, certain amounts as defined in the agreements. The Company does not believe it is probable that it will be required to make such payments; therefore, has not recorded a liability at this time. Such amounts, if any, would not be expected to be material to the Company s financial position or results of operations.

Credit Facility

At December 31, 2006 the Company had an $800.0 million senior secured revolving credit facility with a maturity of August 2010, and a borrowing base of $480.0 million (Credit Facility). In February 2007, in conjunction with the Stallion acquisition and two acquisitions in West Virginia (see Note 2 in Notes to Consolidated Financial Statements) the Company amended its Credit Facility, increasing the borrowing base to $725.0 million. In connection with this amendment, in the first quarter of 2007, the Company paid fees of approximately $1.5 million, which will be amortized over the remaining term of the Credit Facility, and wrote-off deferred financing fees of approximately $0.5 million. At February 28, 2007, we had $120.2 million available for borrowing under our 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. Our obligations under the Credit Facility are secured by mortgages on our oil and gas properties as well as a pledge of all ownership interests in our operating subsidiaries. We are required to maintain the mortgages on properties representing at least 80% of our oil and gas properties. Additionally, the obligations under the Credit Facility are guaranteed by all of our operating subsidiaries and may be guaranteed by any future subsidiaries.

At our election, interest on the Credit Facility is determined by reference to LIBOR plus an applicable margin between 1.00% and 1.75% per annum; or a domestic bank rate plus an applicable margin between 0.00% and 0.25% per annum. Interest is payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

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

The Credit Facility contains various covenants that limit the Company s ability to incur additional indebtedness, make acquisitions or certain capital expenditures; make distributions other than from available cash; merge or consolidate; and engage in certain asset dispositions. The Credit Facility also contains covenants that require the Company to maintain the following financial ratios:

- consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization and other similar changes, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures, to interest expense of not less than 2.5 to 1.0

- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under SFAS 133, which includes the current portion of oil and gas and interest rate derivatives

The Credit Facility does not contain a minimum debt to equity ratio requirement. The Company is in compliance with all financial and other covenants of its Credit Facility.

The Company repaid $53.3 million of borrowings under its Credit Facility in October 2006 (see Private Placement Class B Units above).

Subordinated Term Loan

In October 2005, we entered into a facility for a $60.0 million second lien senior subordinated term loan. The proceeds of the subordinated term loan were used to fund a portion of the purchase price for the acquisition of oil and gas properties from Exploration Partners. The outstanding balance was paid in full in 2006, with proceeds from our IPO.

Subordinated Bridge Loan

In August 2006, in order to fund a portion of the acquisitions of Blacksand and the Kaiser-Francis Assets, we entered into a $250.0 million Subordinated Bridge Loan with a termination of August 1, 2007. The Company repaid in full the Subordinated Bridge Loan in October 2006 (see Private Placement Class B Units above).

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

Contractual Obligations

A summary of our long-term contractual obligations as of December 31, 2006 is provided in the following table:

Contractual Obligations	Payments Due Total	Less than 1 Year	2 3 Years	4 -5 Years	After 5 Years
	(in thousands)				
Long-term Debt Obligations:					
Long-term notes payable	$ 3,361	$ 874	$ 1,511	$ 675	$ 301
Credit facility	425,750			425,750	
Interest on credit facility computed at 7.125%	108,699	30,335	60,669	17,695	
Operating Lease Obligations:					
Office and office equipment leases	8,837	825	2,104	2,232	3,676
Other Long-term Liabilities:					
Asset retirement obligation	8,594			65	8,529
Other:					
Equipment purchases	909	909			
Executive compensation	250	250			
Total	$ 556,400	$ 33,193	$ 64,284	$ 446,417	$ 12,506

Off-Balance Sheet Arrangements

At December 31, 2006, the Company did not have any off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on our financial position or results of operations.

Contingencies

During 2006, 2005, and 2004 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.

Capital Structure

The Company s capitalization, including current maturities of long-term debt, is presented below:

	December 31, 2006	2005
	(in thousands)	
Cash and cash equivalents	$ 6,595	$ 11,041
Credit facility	$ 425,750	$ 207,000
Other long-term liabilities	21,587	34,198
Total long-term debt and other obligations	447,337	241,198
Total unitholders capital (deficit)	449,954	(46,831)
Total capitalization	$ 897,291	$ 194,367

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

Non-GAAP Financial Measure

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) plus:

Interest expense, net of amounts capitalized;
Depreciation, depletion and amortization;
Write-off of deferred financing fees;
(Gain) loss on sale of assets;
(Gain) loss from equity investment;
Accretion of asset retirement obligation;
Unrealized (gain) loss oil and gas derivatives;
Realized (gain) loss on canceled gas swaps;
Unit-based compensation expense;
IPO cash bonuses; and
Income tax (benefit) provision.

The costs of canceling gas swaps before their original settlement date during 2005 were adjustments to Adjusted EBITDA that required expenditure of cash. These costs were financed with borrowings under our credit facility, and such long-term debt is recognized as an increase in cash from financing activities.

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

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

	Year Ended December 31,		
	2006	**2005**	**2004**
	(in thousands)		
Net income (loss)	$ 79,185	$ (56,351)	$ (4,816)
Plus:			
Interest expense, net of amounts capitalized	25,494	7,040	3,530
Depreciation, depletion and amortization	24,173	7,294	3,656
Write-off of deferred financing fees	3,342	364	
Loss on sale of assets	72	39	33
Loss from equity investment		17	56
Accretion of asset retirement obligation	314	172	74
Unrealized (gain) loss on oil and gas derivatives	(77,776)	24,776	8,765
Realized loss on canceled gas derivatives(1)		38,281	
Unit-based compensation expense	21,643		
IPO cash bonuses	2,039		
Income tax (benefit) provision(2)	(3,402)	74	
Adjusted EBITDA	$ 75,084	$ 21,706	$ 11,298

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

(2) The Company s taxable subsidiaries generated net operating losses for the year. Management has subsequently recovered expenses through an intercompany charge for services from Linn Operating, Inc. to Linn Energy, LLC, which should result in a corresponding tax expense in first quarter of 2007.

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

As noted above, Adjusted EBITDA is a non-GAAP performance measure used by our management and is a quantitative measure used in the oil and gas industry. On our consolidated statement of cash flows for the year ended December 31, 2006, net cash used in operating activities was approximately $6.8 million and includes approximately $20.4 million realized gain on oil and gas and interest rate swap derivatives and $2.0 million of bonuses paid to executive officers in connection with our IPO. On our consolidated statement of cash flows for the year ended December 31, 2005, net cash used in operating activities was approximately $29.5 million and includes approximately $51.4 million realized loss on oil and gas and interest rate swap derivatives. On our consolidated statement of cash flows for the year ended December 31, 2004, net cash provided by operating activities was approximately $10.4 million and includes approximately $2.2 million realized loss on oil and gas and interest rate swap derivatives.

Competition

The oil and gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects, than our financial or human resources permit.

We are 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. We are unable to predict when, or if, such shortages may occur or how they would affect our drilling program. We purchased two drilling rigs during 2006, at a cost of approximately $2.2 million per rig, an additional rig in the first quarter of 2007, and currently have contracts in place for additional third-party drilling rigs needed to carry out our 2007 drilling program. In the third quarter of 2006, the Company began, for the first time, operating its own drilling rigs, staffed with Company personnel.

Competition is also strong for attractive oil and gas producing properties, undeveloped leases and drilling rights, and we cannot assure that we will be able to compete satisfactorily when attempting to make further acquisitions.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are 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 us 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. We evaluate our estimates and assumptions on a regular basis. We base our 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 our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. These accounting policies reflect our more significant estimates and assumptions used in the preparation of our financial statements. See Note 1 of the Notes to the Consolidated Financial Statements for a discussion of additional accounting policies and estimates made by management.

Oil and Gas Properties

We account for oil and gas properties by the successful efforts method. Leasehold acquisition costs are capitalized when incurred. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for acquisition costs using all proved reserves. SFAS No. 19, *Financial Accounting and Reporting for Oil and Gas Producing Companies* (SFAS 19) requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped and that capitalized development costs (wells and related equipment and facilities) be amortized on the basis of proved developed reserves. As more fully described in the Supplementary Oil and Gas Data (Unaudited) in Item 8. Financial

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

Statements and Supplementary Data, our proved reserves at December 31, 2006 were estimated by an independent petroleum engineering firm, DeGolyer and MacNaughton, and are subject to future revisions based on availability of additional information. As described in Note 11 of the Notes to the Consolidated Financial Statements, we follow SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). Under SFAS 143, estimated asset retirement costs are recognized when the asset is placed in service and are amortized over proved developed reserves using the units of production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Geological, geophysical and dry hole costs on oil and gas properties relating to unsuccessful wells are charged to expense as incurred.

Upon sale or retirement of complete fields of depreciable or depleted property, the book value thereof, less proceeds or salvage value, is charged or credited to income. On sale or retirement of an individual well the proceeds are credited to accumulated depreciation and depletion.

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* we assess proved oil and gas properties for possible impairment when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. We recognize an impairment loss as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the carrying value. If an impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management s expectations for the future and include estimates of oil and gas reserves and future commodity prices and operating costs. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate property impairment. The Company recorded approximately $1.0 million of impairments in 2006, primarily related to downward reserve revisions. See Note 1 in Notes to Consolidated Financial Statements. The impairment expense is included in depreciation, depletion and amortization on the consolidated statement of operations. No impairments were recorded in 2005 or 2004.

Unproved properties that are individually insignificant are amortized. Unproved properties that are individually significant are assessed for impairment on a property-by-property basis. If considered impaired, costs are charged to expense when such impairment is deemed to have occurred.

Oil and Gas Reserve Quantities

The Company s estimates of proved reserves are based on the quantities of oil and gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. DeGolyer and MacNaughton prepared a reserve and economic evaluation of all our properties on a well-by-well basis as of December 31, 2006.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. We prepare our 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 our 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 gas, natural gas liquids and oil eventually recovered.

Revenue Recognition

Sales of oil and gas are recognized when oil or gas 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. Oil and gas is sold by the Company on a monthly basis. Virtually all of the Company s contracts pricing provisions are tied to a market index, with certain adjustments based on, among

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

other factors, whether a well delivers to a gathering or transmission line, quality of oil and gas, and prevailing supply and demand conditions, so that the price of the oil and gas fluctuate to remain competitive with other available oil and gas suppliers. As a result, the Company s revenues from the sale of oil and gas will suffer if market prices decline, and benefit if they increase. The Company believes that the pricing provisions of its oil and gas contracts are customary in the industry.

Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess of the Company s share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. The Company did not have any significant gas imbalance positions at December 31, 2006 or 2005.

Natural gas marketing is recorded on the gross accounting method because the Company takes title to the gas it purchases from the various producers and bears the risks and enjoys the benefits of that ownership. Natural gas marketing revenues and natural gas marketing expense, titled as such, are reported on the consolidated statements of operations for the years ended December 31, 2006, 2005 and 2004.

The Company currently uses the Net-Back method of accounting for transportation arrangements of its gas sales. The Company sells gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by its customers and reflected in the wellhead price.

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

The Company is paid a monthly operating fee for each well it operates for outside owners. The fee covers monthly operating and accounting costs, insurance, and other recurring costs. General and administrative expenses are presented net of approximately $1.1 million, $1.2 million and $0.6 million for the years ended December 31, 2006, 2005 and 2004, respectively, which represent reimbursements from other working interest owners.

Derivative Instruments and Hedging Activities

We use derivative financial instruments to achieve a more predictable cash flow from our oil and gas production by reducing our exposure to price fluctuations. Currently, these transactions consist of fixed price swaps and puts. Additionally, we use derivative financial instruments in the form of interest rate swaps to mitigate our interest rate exposure. We account 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 market value and included in the balance sheet as assets or liabilities.

The accounting for changes in the fair market value of a derivative instrument depends on the intended use of the derivative instrument and the resulting designation, which is established at the inception of a derivative instrument. SFAS 133 requires that a company formally document, at the inception of a hedge, the hedging relationship and the company s risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment.

A put option requires us to pay the counterparty 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. The costs incurred to enter into the transactions are expensed as incurred, and the change in fair market value of the instrument is reported in the statement of operations each period.

We did not designate any of our derivative instruments as hedges under SFAS 133, even though they protected us from changes in commodity prices. Therefore, the changes in fair value of these instruments were recorded in our current earnings. These amounts are non-cash gains or losses.

See Item 7A. Quantitative and Qualitative Disclosure About Market Risk for discussion regarding the Company s sensitivity analysis for the Company s financial instruments and interest rate swaps.

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

Purchase Accounting

The establishment of our asset base through December 31, 2006 has included 14 acquisitions of oil and gas properties. Three additional acquisitions were completed in February 2007. These acquisitions have been accounted for using the purchase method of accounting as prescribed in SFAS No. 141, *Business Combinations.* See Note 2 in Notes to Consolidated Financial Statements.

In connection with a purchase 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 an 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. In each of our acquisitions it was determined that the purchase price did not exceed the fair value of the net assets acquired. Therefore, no goodwill was recorded.

In estimating the fair values of assets acquired and liabilities assumed we made various assumptions. 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, we prepared estimates of oil and gas reserves. We 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 our 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

We account for unit-based compensation pursuant to SFAS No. 123 (revised 2004), *Shared 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. We also follow 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. We recorded no unit-based compensation expense for the years ended December 31, 2005 and 2004, as there were no unit-based payments made during the respective periods.

New Accounting Pronouncements

There have been no new accounting standards that materially affected the Company this period.

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 our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in gas 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 we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and gas production. Realized pricing is primarily driven by the spot market prices applicable to our oil and gas production and the prevailing price for oil. Pricing for oil and gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control.

We periodically have entered into and anticipate entering into hedging arrangements with respect to a portion of our projected oil and gas production through various transactions that hedge the future prices received. These transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. At the settlement date, we receive the excess, if any, of the fixed floor over the floating rate. Additionally, we have put options for which we pay the counterparty the fair value at the purchase date. These hedging activities are intended to support oil and gas prices at targeted levels and to manage our exposure to oil and gas price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

At December 31, 2006, the fair value of hedges that have settled during 2006 was an asset of approximately $37.8 million and a liability of approximately $0.5 for a net asset of approximately $37.3 million, which we are owed from the counterparty. A 10% increase in the index oil and gas prices above the December 31, 2006 prices for the next twelve months would result in a reduction of approximately $26.8 million in the value of our hedges; conversely, a 10% decrease in the index oil and gas prices would result in an increase of approximately $26.8 million.

Our derivatives as of December 31, 2006 through 2011, are summarized in the table presented in Note 15 in Notes to Consolidated Financial Statements.

Interest Rate Risk

At December 31, 2006, we had long-term debt outstanding of $425.8 million under our Credit Facility, which incurred interest at floating rates in accordance the Credit Facility agreement. As of December 31, 2006, our rate based on the one-month LIBOR was approximately 7.125%. A 1% increase in the one-month LIBOR would result in an estimated $4.3 million increase in annual interest expense.

In order to finance the Stallion acquisition and the acquisitions of certain gas properties in West Virginia, in February 2007, the Company modified its Credit Facility, increasing the borrowing base to $725.0 million. See Note 8 in Notes to Consolidated Financial Statements.

We have periodically entered into interest rate swap agreements to minimize the effect of fluctuations in interest rates. We are required to pay our counterparties the difference between and the fixed rate in the contract and the actual rate if the actual rate is lower than the fixed rate and conversely, our counterparties are required to pay us if the actual rate is higher than the fixed rate in the contract. At December 31, 2006, we had two interest rate swaps outstanding with notional amounts of $50.0 million for 2007 and 2008, and fixed interest rates of 5.30% and 5.79%, respectively.

A 1% change in LIBOR as of December 31, 2006 would result in an estimated $1.0 million change in annual interest expense associated with our interest swap agreements.

Under the terms of the swap agreements, we receive quarterly interest payments at the three-month LIBOR rate.

We did not designate the interest rate swap agreements we entered into as hedges under SFAS 133, even though they protect us from changes in interest rates. Therefore, the changes in fair value of these instruments were recorded in our current earnings. These amounts are non-cash gains and losses.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS and SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors

Linn Energy, LLC:

We have audited the accompanying consolidated balance sheets of Linn Energy, LLC and subsidiaries as of December 31, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Houston, Texas

March 29, 2007

LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2006	2005
	(in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 6,595	$ 11,041
Receivables - trade, net	19,124	17,753
Fair value of interest rate swaps	44	202
Inventory	578	68
Current portion of oil and gas derivatives	37,773	1,601
Current portion of deferred tax assets, net	3,344	
Other current assets	2,218	4,068
Total current assets	69,676	34,733
Oil and gas properties and related equipment (successful efforts method)	766,638	250,000
Less accumulated depreciation, depletion and amortization	(33,349)	(10,707)
	733,289	239,293
Property and equipment, net	20,754	2,525
Other assets:		
Long-term portion of oil and gas derivatives	70,435	2,795
Deferred tax assets, net	16	
Deposit for oil and gas properties	20,086	
Deferred financing fees and other assets, net	2,052	1,578
	92,589	4,373
Total assets	$ 916,308	$ 280,924

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

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LINN ENERGY, LLC
CONSOLIDATED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(in thousands, except unit amounts)	
Liabilities and Unitholders Capital (Deficit)		
Current liabilities:		
Current portion of long-term notes payable	$ 873	$ 113
Subordinated term loan		60,000
Accounts payable and accrued expenses	12,506	5,612
Current portion of oil and gas derivatives	462	12,094
Revenue distribution	1,839	6,082
Accrued interest payable	2,084	1,448
Gas purchases payable	253	1,208
Total current liabilities	18,017	86,557
Long-term liabilities:		
Notes payable	2,487	695
Credit facility	425,750	207,000
Interest rate swaps	423	663
Asset retirement obligation	8,594	5,443
Oil and gas derivatives	9,934	27,139
Other long-term liabilities	149	258
Total long-term liabilities	447,337	241,198
Total liabilities	465,354	327,755
Unitholders capital (deficit):		
33,617,187 units issued and outstanding at December 31, 2006	246,034	16,024
9,185,965 Class B units issued and outstanding at December 31, 2006	188,590	
Accumulated income (loss)	16,330	(62,855)
	450,954	(46,831)
Total liabilities and unitholders capital (deficit)	$ 916,308	$ 280,924

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

LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2006	**2005**	**2004**
	(in thousands, except per unit amounts)		
Revenues:			
Oil and gas sales	$ 80,393	$ 44,645	$ 19,502
Gain (loss) on oil and gas derivatives	103,308	(76,193)	(11,004)
Natural gas marketing revenues	5,598	4,722	520
Other revenues	1,759	345	160
	191,058	(26,481)	9,178
Expenses:			
Operating expenses	18,099	7,356	4,756
Natural gas marketing expenses	4,862	4,401	482
General and administrative expenses	39,993	3,332	1,488
Depreciation, depletion and amortization	24,173	7,294	3,656
	87,127	22,383	10,382
	103,931	(48,864)	(1,204)
Other income and (expenses):			
Interest income	761	47	7
Interest expense, net of amounts capitalized	(25,494)	(7,040)	(3,530)
Write-off of deferred financing fees and other losses	(3,415)	(420)	(89)
	(28,148)	(7,413)	(3,612)
Income (loss) before income taxes	75,783	(56,277)	(4,816)
Income tax benefit (provision)	3,402	(74)	
Net income (loss)	$ 79,185	$ (56,351)	$ (4,816)
Net income (loss) per unit:			
Units - basic	$ 2.64	$ (2.75)	$ (0.23)
Units - diluted	$ 2.61	$ (2.75)	$ (0.23)
Class B units - basic	$ 2.64	$	$
Class B units - diluted	$ 2.61	$	$
Weighted average units outstanding:			
Units - basic	28,281	20,518	20,518
Units - diluted	30,385	20,518	20,518
Class B units - basic	1,737		
Class B units - diluted	1,737		
Distributions declared per unit	$ 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 (in thousands)	Accumulated Income (Loss)	Treasury Units (at Cost)	Total Unitholders Capital (Deficit)
Balance as of December 31, 2003	$ 16,024	$ (1,688)	$	$ 14,336
Net loss		(4,816)		(4,816)
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	21,643			21,643
Net income		79,185		79,185
Balance as of December 31, 2006	$ 434,624	$ 16,330	$	$ 450,954

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

LINN ENERGY, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	2006	**2005**	**2004**
	(in thousands)		
Cash flow from operating activities:			
Net income (loss)	$ 79,185	$ (56,351)	$ (4,816)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	24,173	7,294	3,656
Amortization and write-off of deferred financing fees and other losses	4,548	875	212
Accretion of asset retirement obligation	314	172	74
Unit-based compensation	21,643		
Deferred income tax	(3,434)		
Mark-to-market on oil and gas and interest rate derivatives:			
Total (gains) losses	(103,390)	75,207	12,263
Realized gains (losses)	20,442	(51,417)	(2,239)
Premiums paid for oil and gas derivatives	(49,807)	(1,628)	
Changes in assets and liabilities:			
Increase in accounts receivable	(371)	(12,208)	(3,725)
(Increase) decrease in inventory and other assets	2,833	(399)	5
Decrease in accounts payable and accrued expenses	1,633	2,670	1,563
Increase in interest rate derivatives payable			759
Increase (decrease) in revenue distribution	(4,243)	3,589	1,909
Increase in accrued interest payable	636	1,036	189
Increase (decrease) in gas purchases payable	(955)	726	482
Increase (decrease) in other liabilities	(12)	916	19
Net cash provided by (used in) operating activities	(6,805)	(29,518)	10,351
Cash flow from investing activities:			
Acquisition of oil and gas properties	(469,274)	(122,065)	(47,356)
Development of oil and gas properties	(46,963)	(27,145)	(14,719)
Deposit for oil and gas properties	(20,086)		
Purchases of property and equipment	(15,414)	(1,639)	(1,519)
Other investing activities	106	(49)	2,221
Net cash used in investing activities	(551,631)	(150,898)	(61,373)
Cash flow from financing activities:			
Proceeds from sale of initial public offering units	243,149		
Proceeds from private placement of units	305,000		
Redemption of member units	(114,449)		
Proceeds from notes payable		65,295	604
Principal payments on notes payable	(493)	(5,085)	(6)
Proceeds from credit facility	334,000	210,000	30,805
Principal payments on credit facility	(115,250)	(75,605)	
Proceeds from subordinated bridge loan	250,000		
Principal payments on subordinated bridge loan	(250,000)		
Principal payments on subordinated term loan	(60,000)		
Distribution to members	(32,056)		
Offering costs	(1,210)	(3,532)	

Financing fees	(4,701)	(1,804)	(236)
Net cash provided by financing activities	553,990	189,269	31,167
Net increase (decrease) in cash	(4,446)	8,853	(19,855)
Cash and cash equivalents:			
Beginning	11,041	2,188	22,043
Ending	$ 6,595	$ 11,041	$ 2,188

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

LINN ENERGY, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS SUPPLEMENTAL DISCLOSURES

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Supplemental disclosure of cash flow information:			
Cash payments for interest	$ 24,147	$ 6,510	$ 1,960
Supplemental disclosures of non cash investing and financing activities:			
Acquisitions of vehicles and equipment through issuance of notes payable	$ 3,046	$ 421	$
In connection with the purchase of oil and gas properties, liabilities were assumed as follows:			
Fair value of assets acquired	$ 472,499	$ 123,514	$ 49,954
Cash paid	(469,274)	(122,065)	(47,356)
Liabilities assumed	$ 3,225	$ 1,449	$ 2,598

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

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LINN ENERGY, LLC

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Basis of Presentation and Significant Accounting Policies

(a) Organization and Description of Business

Linn Energy, LLC (Linn or the Company) is an independent oil and gas company focused on the development and acquisition of long-lived properties in the United States that began operations in March 2003 and was formed as a Delaware limited liability company in April 2005. Linn is a holding company that conducts its operations through, and its operating assets are owned by, its wholly-owned subsidiaries.

(b) Basis of Presentation

The Company presents its financial statements in accordance with U.S. generally accepted accounting principles (GAAP). Certain amounts in the consolidated financial statements and notes thereto have been reclassified to conform to the 2006 financial statement presentation.

(c) Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. All significant intercompany transactions and balances have been eliminated upon consolidation.

(d) Use of Estimates

Management of the Company has made a number of estimates and assumptions relating to the reporting of assets and liabilities and revenues and expenses and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with GAAP. Actual results could differ from those estimates. The estimates that are particularly significant to the financial statements include estimates of oil and gas reserves, future cash flows from oil and gas properties, depreciation, depletion and amortization, asset retirement obligations, the fair value of derivatives and unit-based compensation expense.

The Company s estimate of proved reserves is based on the quantities of oil and gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. DeGolyer and MacNaughton prepared a reserve and economic evaluation of all the Company s properties on a well-by-well basis at December 31, 2006.

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 Securities and Exchange Commission (SEC) guidelines. The independent engineering firm adheres to the same guidelines when preparing their reserve reports. The accuracy of the Company s 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 gas, natural gas liquids and oil eventually recovered.

(e) Cash Equivalents

For purposes of the statement of cash flows, the Company considers all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

(f) Trade Accounts Receivable, Net

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company routinely assesses the financial strength of its customers and bad debts are recorded based on an account-by-account review after all means of collection have been exhausted and the potential recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The changes in the Company s allowance for doubtful accounts are as follows:

Description	Balance at beginning of year (in thousands)	Additions Charged to costs and expenses	Charged to other accounts	Deductions Write-off adjustments	Balance at end of year
Year Ended December 31, 2006:					
Allowance for doubtful accounts	$ 100	$	$	$	$ 100
Year Ended December 31, 2005:					
Allowance for doubtful accounts	$ 50	$ 50	$	$	$ 100
Year Ended December 31, 2004:					
Allowance for doubtful accounts	$	$ 50	$	$	$ 50

(g) Inventory

Inventory of well equipment, parts, and supplies are valued at cost, determined by the first-in-first-out method.

(h) Oil and Gas Properties

The Company accounts for oil and gas properties by the successful efforts method. Leasehold acquisition costs are capitalized. If proved reserves are found on an undeveloped property, leasehold costs are transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depreciation and depletion of producing oil and gas properties is recorded based on units of production. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Statement of Financial Accounting Standards (SFAS) No. 19, as amended, *Financial Accounting and Reporting by Oil and Gas Producing Companies* (SFAS 19) requires that acquisition costs of proved properties be amortized on the basis of all proved reserves, developed and undeveloped, and that capitalized development costs (wells and related equipment and facilities) be amortized on the basis of proved developed reserves.

Proved reserves are estimated by an independent petroleum engineering firm and are subject to future revisions based on availability of additional information. As described in Note 11, the Company accounts for asset retirement obligations in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). In accordance with SFAS 143, 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.

Geological, geophysical, and exploratory dry hole costs on oil and gas properties relating to unsuccessful exploratory wells are charged to expense as incurred.

Upon sale or retirement of complete fields of depreciable or depleted property, the book value thereof, less proceeds or salvage value, is charged or credited to income. On sale or retirement of an individual well the proceeds are credited to accumulated depreciation and depletion.

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* we assess proved oil and gas properties for possible impairment when events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. We recognize an impairment loss as a result of a triggering event and when the estimated undiscounted future cash flows from a property are less than the carrying value. If impairment is indicated, the cash flows are discounted at a rate approximate to our cost of capital and compared to the carrying value for determining the amount of the impairment loss to record. Estimated future cash flows are based on management s expectations for the future and include estimates of oil and gas reserves and future commodity prices and operating costs. Downward revisions in estimates of

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate property impairment. The Company recorded approximately $1.0 million of impairments in 2006, primarily related to downward reserve revisions in one field in the Appalachian Basin. The impairment expense is included in depreciation, depletion and amortization on the consolidated statement of operations. No impairments were recorded in 2005 or 2004.

Unproven properties that are individually insignificant are amortized. Unproved properties that are individually significant are assessed for impairment on a property-by-property basis. If considered impaired, costs are charged to expense when such impairment is deemed to have occurred.

(i) Property, Plant and Equipment

Property, plant and equipment other than oil and gas properties is carried at cost. Depreciation is provided principally on the straight-line method over useful lives as follows:

Buildings, leasehold improvements and aircraft	7-39 years
Furniture and equipment	3-7 years
Vehicles	5 years

Tangible long-lived assets are evaluated in accordance with SFAS No. 144, *Accounting for the Disposal of Long-Lived Assets,* when events and circumstances indicate that the carrying value of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. No impairments were recorded in 2006, 2005 or 2004.

Maintenance and repairs are charged to expense as incurred. Major renewals and betterments are capitalized. Upon the sale or other disposition of assets, the cost and related accumulated depreciation, depletion, and amortization are removed from the accounts, the proceeds applied thereto, and any resulting gain or loss is reflected in income for the period.

(j) Derivative Instruments and Hedging Activities

The Company uses derivative financial instruments to achieve a more predictable cash flow from its oil and gas production by reducing its exposure to price fluctuations. As of December 31, 2006, these transactions were in the form of swaps and puts. Additionally, the Company uses derivative financial instruments in the form of interest rate swaps to mitigate its interest rate exposure. The Company accounts for its derivatives at fair value as an asset or liability and the change in the fair value of derivatives is included in income. The Company accounts for these activities pursuant to SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, (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 accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. SFAS 133 requires that a company formally document, at the inception of a hedge, the hedging relationship and the entity s risk management objective and strategy for undertaking the hedge, including identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the method that will be used to assess effectiveness and the method that will be used to measure hedge ineffectiveness of derivative instruments that receive hedge accounting treatment. None of the Company s commodity or interest rate derivatives are designated as hedges and therefore the change in the fair value of the derivatives is included in the consolidated statements of operations. See Note 10 and Note 15 for discussion related to derivative financial instruments.

(k) Unit-Based Compensation

SFAS No. 123 (revised 2004), *Share Based Payment* (SFAS 123R) requires the recognition of compensation expense, over the requisite service period, in an amount equal to the fair value of unit-based

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

payments granted to employees and non-employee directors. The fair value of the unit-based payments, excluding liability awards, is computed at the date of grant and will not be remeasured. The fair value of liability awards is remeasured at each reporting date through the settlement date with the change in fair value recognized as compensation expense over that period. The Company currently does not have any awards accounted for as liability awards. SFAS 123R also requires the benefits of tax deductions in excess of recognized compensation costs to be reported as financing cash flow, rather than as an operating cash flow as required under prior guidance. This requirement will reduce net operating cash flows and increase net financing cash flows in periods after adoption in which such tax deduction exists. The Company had no excess tax deductions during 2006.

The Company has made a policy decision, in accordance with the provisions of SFAS 123R, to recognize compensation cost for service-based awards on a straight-line basis over the requisite service period. The Company did not issue any unit-based compensation awards prior to January 2006. See Note 7 for a discussion of the Company s accounting for unit-based compensation expense.

(l) Revenue Distribution

Revenue distribution on the consolidated balance sheets of $1.8 million and $6.1 million represents amounts owed to working interest and royalty interest owners as of December 31, 2006 and 2005, respectively.

(m) Offering Costs

Other current assets at December 31, 2006 include approximately $56,000 of costs incurred in connection with a private placement in February 2007 (see Note 4). These were reclassified to unitholders capital upon receipt of the proceeds in the first quarter of 2007. At December 31, 2005 other current assets include costs of $3.5 million incurred in connection with the Company s initial public offering (IPO). The Company reclassified these deferred offering costs to unitholders capital upon receipt of the proceeds from the IPO during the first quarter of 2006 (see Note 3).

(n) Deferred Financing Fees

The Company incurred legal and bank fees related to the issuance of debt (see Note 8). The financing fees incurred for the years ended December 31, 2006, 2005 and 2004 were $4.7 million, $1.8 million and $0.2 million, respectively. These debt issuance costs are amortized over the life of the debt agreement. For the years ended December 31, 2006, 2005 and 2004, amortization expense of $1.1 million, $0.5 million and $0.1 million, respectively, is included in interest expense. Deferred financing fees of approximately $3.3 million, $0.4 million and zero were written-off in connection with refinancings during the years ended December 31, 2006, 2005 and 2004, respectively. In the first quarter of 2007, the company wrote-off approximately $0.5 million of deferred financing fees in connection with an amendment to its credit facility (see Note 8).

(o) Fair Value of Financial Instruments

The carrying values of the Company s receivables, payables and debt are estimated to be substantially the same as their fair values at December 31, 2006 and 2005.

(p) Unitholders Capital

The operations of the Company are governed by the provisions of a limited liability company agreement executed by and among its members. The agreement includes specific provisions with respect to the maintenance of the capital accounts of each of the Company s unitholders. The total capital contributed by the members as of December 31, 2005 was $16.3 million. Quantum Energy Partners share of the contribution was $15.0 million.

Pursuant to applicable provisions of the Delaware Limited Liability Company Act (the Delaware Act) and the Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC (the Agreement), unitholders have no liability for the debts, obligations and liabilities of the Company, except as expressly required in the Agreement or the Delaware Act. Pursuant to the terms of the Agreement, unitholders are entitled to vote on the following matters:

- the annual election of the Company s Board of Directors;

- specified amendments to the Agreement;

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

- the merger of the Company or the sale of all or substantially all of the Company s assets; and
- the dissolution of the Company.

The Company will remain in existence unless and until dissolved in accordance with the terms of the Agreement. See Note 4 for discussion of our Class B units and Class C units.

(q) Operating Fee

The Company is paid a monthly operating fee for each well it operates for outside owners. The fee covers monthly operating and accounting costs, insurance, and other recurring costs. As the operating fee is a reimbursement for costs incurred on behalf of third parties, the portion of the fee that exceeds the reimbursement of operating costs has been netted against general and administrative expense. For the years ended December 31, 2006, 2005 and 2004, the operating fees netted against general and administrative expense were approximately $1.1 million, $1.2 million and $0.6 million, respectively.

(r) Income Taxes

The Company is a limited liability company treated as a partnership for federal and state income tax purposes with all income tax liabilities and/or benefits of the Company being passed through to the unitholders. As such, no recognition of federal or state income taxes for the Company or its subsidiaries that are organized as limited liability companies have been provided for in the accompanying financial statements except as described below.

Certain of the Company s subsidiaries are Subchapter C-corporations subject to corporate income taxes, which are accounted for under the provisions of SFAS No. 109 *Accounting for Income Taxes* (SFAS 109), which uses the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. See Note 17 for detail of amounts recorded in our consolidated financial statements.

(s) Revenue Recognition

Sales of oil and gas are recognized when oil or gas 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. Oil and gas is sold by the Company on a monthly basis. Virtually all of the Company s contracts 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 and gas, and prevailing supply and demand conditions, so that the price of the oil and gas fluctuate to remain competitive with other available oil and gas suppliers.

Gas imbalances occur when the Company sells more or less than its entitled ownership percentage of total gas production. Any amount received in excess of the Company s share is treated as a liability. If the Company receives less than its entitled share, the underproduction is recorded as a receivable. The Company did not have any significant gas imbalance positions at December 31, 2006 or 2005.

Natural gas marketing is recorded on the gross accounting method because the Company takes title to the gas it purchases from the various producers and bears the risks and enjoys the benefits of that ownership. Natural gas marketing revenues and natural gas marketing expenses, titled as such, are reported on the consolidated statements of operations for the years ended December 31, 2006, 2005 and 2004.

The Company currently uses the Net-Back method of accounting for transportation arrangements of its gas sales. The Company sells gas at the wellhead and collects a price and recognizes revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by its customers and reflected in the wellhead price.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

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

(t) *Production Taxes*

Oil and gas revenues are presented on a gross basis on the consolidated statements of operations. Production taxes are included in operating expenses on the consolidated statements of operations and were approximately $2.0 million, $0.7 million and $0.4 million for the years ended December 31, 2006, 2005 and 2004, respectively.

(u) *Recently Issued Accounting Standards*

In June 2006, the FASB issued Financial Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109* (FIN 48). The interpretation sets forth a consistent recognition threshold and measurement attribute, and criteria for subsequently recognizing, derecognizing and measuring uncertain tax positions for financial statement purposes. FIN 48 also requires expanded disclosure with respect to the uncertainty in income taxes. The interpretation is effective for fiscal years beginning after December 31, 2006. The Company is currently evaluating the effect that the adoption of FIN 48 will have on its results of operations and financial condition, but does not expect it will have a material impact.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS 157), which provides guidance for using fair value to measure assets and liabilities. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value and clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk, not just the company s mark-to-market value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Company is currently evaluating the effect that the implementation of SFAS 157 will have on its results of operations and financial condition, but does not expect it will have a material impact.

In September 2006, the SEC issued Staff Accounting Bulletin No. 108 (SAB 108). SAB 108 expresses the SEC staff s views regarding the process of quantifying financial statement misstatements. The SEC staff believes registrants should quantify errors using both a balance sheet and an income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The SEC staff will not object if a registrant records a one-time cumulative effect adjustment to correct errors existing in prior years that previously had been considered immaterial, quantitatively and qualitatively, based on appropriate use of the registrant s approach. SAB 108 describes the circumstances where this would be appropriate as well as required disclosures to investors. SAB 108 is effective for fiscal years ending on or after November 15, 2006. The initial adoption of SAB 108 had no effect on our results of operations or financial position.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

(2) Acquisitions

The Company accounts for its acquisitions using the purchase method of accounting as prescribed in SFAS No. 141, *Business Combinations.* The following provides a summary of the Company s acquisitions during 2006 and 2005, as well as acquisitions subsequent to December 31, 2006.

Acquisitions 2006

In the second quarter of 2006, the Company purchased from the owners of property operated by Devonian Gas Production, Inc., Excel Energy, Inc. and T&F Exploration LP, oil and gas properties and tangible wellhead equipment in West Virginia, for an aggregate purchase price of approximately $27.5 million. Also in the second quarter of 2006, the Company purchased a gas gathering pipeline system in western Pennsylvania for approximately $1.0 million.

In the third quarter of 2006, the Company acquired certain affiliated entities of Blacksand Energy, LLC (Blacksand), located in the Los Angeles Basin, for an aggregate purchase price, including transaction costs and assumed liabilities, of approximately $301.0 million and certain Mid-Continent assets of Kaiser-Francis Oil Company (Kaiser-Francis Assets) located in Oklahoma for an aggregate purchase price, including transaction costs and assumed liabilities, of approximately $126.4 million.

The acquisition of Blacksand was completed on August 1, 2006. The acquisition of the Kaiser-Francis Assets was completed on August 14, 2006, effective September 1, 2006. The results of operations of Blacksand and the Kaiser-Francis Assets are included in the consolidated results of the Company effective August 1, 2006 and September 1, 2006, respectively.

The acquisitions of the Kaiser-Francis Assets and Blacksand were financed with a combination of borrowings under our senior secured revolving credit facility and a $250.0 million subordinated bridge loan (see Note 8).

The following table presents the aggregate purchase prices of the Blacksand and Kaiser-Francis acquisitions as of the respective acquisition dates:

	Blacksand (in thousands)	**Kaiser-Francis**
Cash	$ 298,113	$ 125,000
Estimated transaction costs	472	1,010
Total purchase price	298,585	126,010
Liabilities assumed	2,373	359
Total purchase price plus liabilities	$ 300,958	$ 126,369

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents, as of the respective acquisition dates, allocations of the purchase prices based on estimates of fair value:

	Blacksand (in thousands)	Kaiser-Francis
Field inventory	$ 284	$
Oil and gas properties	300,187	126,369
Vehicles and buildings	487	
	$ 300,958	$ 126,369

The purchase price allocations are based on independent appraisals, discounted cash flows, quoted market prices and estimates by management. 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, we prepared estimates of oil and gas reserves. We 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. In addition, when appropriate, the Company also reviewed comparable purchases and sales of oil and gas properties within the same regions, and used that data as a proxy for fair market value; i.e., the amount a willing buyer and seller would enter into an exchange for such properties.

The following unaudited pro forma financial information presents a summary of Linn s consolidated results of operations for the years ended December 31, 2006 and 2005, assuming the acquisitions of Blacksand, the Kaiser-Francis Assets and Exploration Partners, LLC (Exploration Partners) had been completed as of January 1, 2005, including adjustments to reflect the allocation of the purchase prices to the acquired net assets. The Exploration Partners acquisition (see Acquisitions 2005 below) was effective October 27, 2005, and its results are included in the actual results of the Company as of that date. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of these dates.

	For the Year Ended December 31, 2006 (in thousands)	2005
Total revenues	$ 255,686	$ 34,656
Total operating expenses	105,974	55,580
Net income (loss)	104,142	(70,926)
Net income (loss) per unit:		
Units - basic	$ 3.47	$ (3.46)
Units - diluted	$ 3.43	$ (3.46)
Class B units - basic	$ 3.47	$
Class B units - diluted	$ 3.43	$

The pro forma results of operations present net income (loss) per unit allocated to the units and Class B units. In January 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of each of the Class B units into units (see Note 4). Therefore, pro forma net income (loss) per unit assumes that the units and Class B units share equally in the pro forma net income (loss) of the Company.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The pro forma results of operations for the year ended December 31, 2006 includes a Blacksand historical gain on property sale of $32.7 million. Had this gain been excluded, pro forma net income for the year ended December 31, 2006 would have been reduced by the gain recorded.

Acquisitions 2005

In the second quarter of 2005, the Company purchased from Columbia Natural Resources, LLC, oil and gas properties, tangible wellhead equipment and a gathering system in West Virginia and western Virginia, for a purchase price of $4.4 million. In the third quarter of 2005, the Company purchased, from GasSearch Corporation, oil and gas properties and tangible wellhead equipment in West Virginia, for a purchase price of $5.4 million and from Exploration Partners, oil and gas properties, oil field equipment and tangible wellhead equipment in West Virginia and Virginia, for a purchase price of $111.4 million. Results of operations for each acquisition are included in the consolidated results of operations of the Company as of the acquisition dates.

Subsequent Event Acquisitions

On February 1, 2007, effective January 1, 2007, the Company completed the acquisition of certain oil and gas properties and related assets in the Texas Panhandle from Cavallo Energy LP, acting through its general partner, Stallion Energy LLC (Stallion) for a contract price of $415.0 million, subject to customary post-closing adjustments. In addition, in January 2007, the Company completed the acquisitions of certain gas properties located in the Appalachian Basin of West Virginia for an aggregate contract price of $39.0 million, subject to customary post-closing adjustments. The purchase price includes a payment of $20.0 million paid by the Company to the seller in December 2006. At December 31, 2006, this amount is reported separately on the consolidated balance sheet within other assets, along with Stallion acquisition costs incurred prior to year end. These acquisitions were financed with a combination of private placements of our units (see Note 4) and borrowings under the Company s senior secured revolving credit facility. In connection with these acquisitions, the Company amended its credit facility to increase the borrowing base from $480.0 million to $725.0 million (see Note 8).

The following table presents the preliminary purchase price for the Stallion acquisition based on preliminary estimates of fair value:

	Stallion (in thousands)
Cash	$ 409,763
Estimated transaction costs	3,300
Total purchase price	413,063
Liabilities assumed	912
Total purchase price plus liabilities	$ 413,975

The following table presents the preliminary allocation of the purchase price based on preliminary estimates of fair value:

	Stallion (in thousands)
Oil and gas properties	$ 413,494
Vehicles and buildings	481
Total purchase price plus liabilities	$ 413,975

The preliminary purchase price allocation is based on preliminary information and estimates by management as final appraisals of assets acquired and liabilities assumed are not yet complete. The purchase price allocation will be completed within one year of the acquisition date.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

(3) Initial Public Offering

In the first quarter of 2006, the Company completed its IPO of 12,450,000 units representing limited liability interest in the Company at $21.00 per unit, for net proceeds, after underwriting discounts of $18.3 million and offering expenses of $4.3 million, of $238.8 million, of which $122.0 million was used to reduce indebtedness under the Company s senior secured revolving credit facility and repay, in full, the subordinated term loan, $114.4 million was used to redeem a portion of the membership interests in the Company and units held by certain affiliated and non-affiliated holders and approximately $2.0 million was used to pay bonuses to certain executive officers of the Company.

(4) Private Placements of Equity

Class B Units

In October 2006, the Company completed a Class B Unit and Unit Purchase Agreement with a group of institutional investors whereby it privately placed 9,185,965 Class B units at a price of $20.55 per unit, and 5,534,687 units at a price of $21.00 per unit, for aggregate gross proceeds of $305.0 million (the Class B Private Placement). In January 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of each of the Class B units into units. In connection with the Class B Private Placement, the Company agreed to file a registration statement with the SEC covering the units and the units underlying the Class B units. In accordance with the agreement, the registration statement must be declared effective by the SEC no later than 210 days following the closing (extended by separate agreement from 165 days).

All proceeds from the Class B Private Placement were used to repay in full the Company s $250.0 million subordinated bridge loan and $53.3 million of borrowings under its credit facility (see Note 8). In connection with the repayment of the subordinated bridge loan, the Company wrote off approximately $2.7 million of deferred financing fees, which was recognized as expense in the fourth quarter of 2006.

Subsequent Event Class C Units

In February 2007, the Company completed a Class C Unit and Unit Purchase Agreement with a group of institutional investors whereby it privately placed 7,465,946 Class C units at a price of $25.06 per unit, and 6,650,144 units at a price of $26.00 per unit, for aggregate gross proceeds of $360.0 million (the Class C Private Placement). The proceeds from the Class C Private Placement were used to finance the Stallion acquisition and the acquisitions of certain gas properties in West Virginia (see Note 2).

The Class C units represent a new class of equity securities that is entitled to a special quarterly distribution equal to 115% of the distribution received by the existing units. The Class C units have no voting rights other than as required by law and are subordinated to the units on dissolution and liquidation. If approved by a vote of the Company s unitholders at the special meeting to be held in April 2007, the Class C units will convert to units on a one-for-one basis. In connection with the Class C Private Placement, the Company agreed to file a registration statement with the SEC covering the units and the units underlying the Class C units. In accordance with the agreement, the registration statement must be declared effective by the SEC no later than 165 days following the closing.

Under the terms of the Class B Private Placement and the Class C Private Placement, if the registration statements are not declared effective in accordance with the respective agreements, the Company could be required to pay purchasers, as liquidated damages and not as a penalty, certain amounts as defined in the agreements. The Company does not believe it is probable that it will be required to make such payments; therefore, has not recorded a liability at this time. Such amounts, if any, would not be expected to be material to the Company s financial position or results of operations.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

(5) Business and Credit Concentrations

Cash

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

Revenue and Trade Receivables

The Company has a concentration of customers who are engaged in oil and gas production within the United States. This concentration of customers may impact the Company s overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. The Company performs ongoing credit evaluations of its customers and typically does not require collateral.

A majority of the Company s largest customers are oil and gas producers, suppliers and operators. For the year ended December 31, 2006, the Company s two largest customers represented 54% and 17% of the Company s sales. The Company s three largest customers represented approximately 48%, 14%, and 10% of the Company s sales for the year ended December 31, 2005. For the year ended December 31, 2004, the Company s four largest customers represented approximately 33%, 19%, 16%, and 13% of the Company s sales.

At December 31, 2006, three customers trade accounts receivable from oil and gas sales accounted for more than 10% of the Company s total trade accounts receivable. As of December 31, 2006, trade accounts receivable from our three largest customers represented approximately 41%, 22% and 16% of the Company s receivables. At December 31, 2005, two customers trade accounts receivable from oil and gas sales accounted for more than 10% of the Company s total trade accounts receivable. Trade accounts receivable for the two largest customers represented approximately 70% and 13% of the Company s receivables as of December 31, 2005.

(6) Property and Equipment

Property and equipment consists of the following:

	December 31, 2006 (in thousands)	2005
Land	$ 308	$ 203
Buildings and leasehold improvements	2,759	608
Vehicles	3,097	1,317
Aircraft	5,890	
Drilling equipment	8,611	
Furniture and equipment	1,966	888
	22,631	3,016
Less: accumulated depreciation	(1,877)	(491)
	$ 20,754	$ 2,525

Depreciation expense on the above assets for the years ended December 31, 2006, 2005 and 2004 was approximately $1.4 million, $0.9 million and $0.2 million, respectively.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

(7) Unit-Based Compensation and Other Benefit Plans

Incentive Plan Summary

The Linn Energy, LLC Long-Term Incentive Plan (the Plan) became effective in December 2005. The Plan, which is administered by the Compensation Committee of the Board of Directors, permits the granting of unit grants, unit options, restricted units, phantom units and unit appreciation rights to employees, consultants and non-employee directors under the terms of the Plan. The unit options and restricted units vest ratably over one to three years from the grant date of the award, unless other contractual arrangements are made. The contractual life of unit options is 10 years. Unit awards were issued for the first time in January 2006, in conjunction with the Company s IPO. No unit options were exercised during the year ended December 31, 2006.

The Plan limits the number of units that may be delivered pursuant to awards to 3.9 million units, provided that no more than 1.5 million units (increased from 500,000 units by a January 2007 Plan amendment) may be issued as restricted units. The Board of Directors and the Compensation Committee of the Board of Directors have the right to alter or amend the Plan or any part of the Plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval as required by the exchange upon which the units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the benefits to the participant without the consent of the participant.

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

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

Unit Options A unit option is a right to purchase a unit at a specified price at terms determined by the Compensation Committee. Unit options will have an exercise price that will not be less than the fair market value of the units on the date of grant, and in general, will become exercisable over a vesting period but may accelerate upon the achievement of specified financial objectives, or upon a change in control of the Company. If a grantee s employment or relationship terminates for any reason, the grantee s unvested unit options will be automatically forfeited unless the option agreement or the Compensation Committee provides otherwise.

Restricted Units A restricted unit is a unit that vests over a period of time and that during such time is subject to forfeiture, and may contain such terms as the Compensation Committee shall determine, including the period over which restricted units (and distributions related to such units) will vest. The Company intends the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our units. Therefore, plan participants will not pay any consideration for the restricted units they receive. If a grantee s employment, consulting relationship or membership on the Board of Directors terminates for any reason, the grantee s unvested restricted units will be automatically forfeited unless the Compensation Committee or the terms of the award agreement provide otherwise.

Phantom Units/Unit Appreciation Rights These awards may be settled in units, cash or a combination thereof. Such grants will contain terms as determined by the Compensation Committee, including the period or terms over which phantom units will vest. If a grantee s employment or service relationship terminates for any reason, the grantee s phantom units or unit appreciation rights will be automatically forfeited unless, and to the extent, the Compensation Committee or the terms of the award agreement provide otherwise. While phantom units require no payment from the grantee, unit appreciation rights will have an exercise price that will not be less than the fair market value of the units on the date of grant. At December 31, 2006, the Company had 9,000 phantom units issued and outstanding. To date, the Company has not issued unit appreciation rights.

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Securities Authorized for Issuance Under the Plan

As of December 31, 2006, approximately 2.1 million units were issuable under the Plan pursuant to outstanding award or other agreements and an additional 1.7 million units were reserved for future issuance under the Plan.

Accounting for Unit-Based Compensation

SFAS 123R requires an entity to recognize as expense beginning at the grant date, the fair value of unit options and other equity-based compensation issued to employees and non-employee directors. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period using the straight-line method in the Company s consolidated statements of operations.

SFAS 123R provides specific guidance on income tax accounting and clarifies how SFAS No.109, *Accounting for Income Taxes* (SFAS 109) should be applied to unit-based compensation. For example, the expense for types of option grants is only deductible for tax purposes at the time that the taxable event takes place. SFAS 123R does not allow companies to predict when these taxable events will take place. Furthermore, it requires that the benefits associated with the tax deductions in excess of recognized compensation cost be reported as a financing cash flow, rather than as an operating cash flow as required under SFAS No. 123 *Accounting for Stock-Based Compensation.* This requirement will reduce net operating cash flows and increase net financing cash flows. These future amounts cannot be estimated, because they depend on, among other things, when employees exercise unit options.

For the year ended, December 31, 2006, we recorded unit-based compensation expense of approximately $21.6 million, as a charge against income before income taxes and it is included in general and administrative expense on the consolidated statement of operations. No related income tax benefit was recognized due to non-deductibility and recognition of a valuation allowance for resulting net operating losses. The Company recorded no unit-based compensation for the years ended December 31, 2005 or 2004, as there were no unit-based awards granted during those periods.

Restricted/Unrestricted Units

The fair value of unrestricted unit grants and restricted units issued is determined based on the fair market value of the Company units on the date of grant. This value is amortized over the vesting period, which varied from one month to two years from the date of grant for certain officers. A summary of the status of the non-vested units as of December 31, 2006, is presented below:

	Number of Non-vested Units	Weighted Average Grant Date Fair Value
Non-vested units at December 31, 2005		$
Granted	1,239,145	22.98
Vested	(114,455)	21.00
Forfeited		
Non-vested units at December 31, 2006	1,124,690	$ 23.19

As of December 31, 2006, there was approximately $7.5 million of unrecognized compensation cost related to non-vested restricted units. The cost is expected to be recognized over a weighted average period of approximately 1.3 years. The total fair value of units that vested during the period was approximately $2.4 million. The terms of these units provided immediate vesting at the grant date. Subsequent to December 31, 2006, the Company granted an aggregate 400,500 restricted units to employees as part of its annual review of employee compensation and 50,000 restricted units to a new officer of the Company.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Changes in Unit Options and Unit Options Outstanding

The following table provides information related to unit option activity for the year ended December 31, 2006:

`	Number of Units Underlying Options	Weighted Average Exercise Price Per Unit	Weighted Average Grant Date Fair Value	Weighted Average Remaining Contractual Life in Years
Outstanding at December 31, 2005		$	$	
Granted	1,019,584	23.90	3.59	
Exercised				
Forfeited	(89,084)	20.39	2.62	
Outstanding at December 31, 2006	930,500	$ 24.24	$ 3.68	9.51
Exercisable at December 31, 2006	30,000	$ 20.18	$ 2.52	9.17

The following table summarizes information about unit options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at December 31, 2006	Weighted Average Remaining Contractual Life	Weighted Average Exercise Prices	Number Exercisable at December 31, 2006	Weighted Average Exercise Prices
$19.74 - $23.50(a)	499,500	9.15	$ 20.61	30,000	$ 20.18
$27.94 - $32.18(b)	431,000	9.92	$ 28.43		
	930,500			30,000	

(a) Represents options issued between January and August 2006.

(b) Represents options issued in December 2006.

As of December 31, 2006, there was approximately $2.7 million of total unrecognized compensation cost related to non-vested unit options. The cost is expected to be recognized over a weighted average period of approximately 1.8 years. In addition, the exercisable unit options at December 31, 2006 have an aggregate intrinsic value of approximately $0.4 million and all outstanding unit options have an aggregate intrinsic value of approximately $7.2 million. The total fair value of all options that vested during the year was approximately $76,000. No options expired during the year. Subsequent to December 31, 2006, the Company granted 50,000 unit options to a new officer of the Company.

The fair value of unit-based compensation for unit options was estimated on the date of grant using a Black-Scholes pricing model based on certain assumptions. The Company s determination of the fair value of unit-based payment awards is affected by the Company s unit price as well as assumptions regarding a number of highly complex and subjective variables. The Company s employee unit options have various restrictions including vesting provisions and restrictions on transfers and hedging, among others, and often are expected to be exercised prior to their contractual maturity. Expected volatilities used in the estimation of fair value have been determined using available volatility data for the Company as well as an average of volatility computations of other identified peer companies in the oil and gas industry. Expected distributions are estimated based on the Company s distribution rate at the date of grant. Historical data of the Company and other identified peer companies is used to estimate unit option exercises and expected term. Forfeitures are estimated using historical Company data and are revised, if necessary, in subsequent periods if actual forfeitures differ from estimates. All employees granted awards have been determined to have similar behaviors for purposes of determining the expected term used to estimate fair value. The

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

risk-free rate for periods within the contractual term of the unit option is based on the U.S. Treasury yield curve in effect at the time of grant. The fair values of the unit option grants were based upon the following assumptions:

Expected volatility	29.70	%	-	31.30%
Expected distributions	7.20	%	-	8.50%
Risk free rate	4.31	%	-	5.04%
Expected term	5.0	years		

Although the fair value of unit option grants is determined in accordance with SFAS 123R using a Black-Scholes option-pricing model, that value may not be indicative of the fair value observed in a willing buyer/willing seller market transaction.

Defined Contribution Plan

The Company sponsors a 401(k) defined contribution plan for eligible employees, effective in January 2005. Company contributions to the 401(k) plan consist of a discretionary matching contribution equal to 100% of the first 4% of eligible compensation contributed by the employee on a before-tax basis. The Company contributed approximately $0.2 million and $0.1 million during the years ended December 31, 2006 and 2005, respectively, to the 401(k) plan s trustee account. The 401(k) plan funds are held in a trustee account on behalf of the plan participants.

(8) Debt

Credit Facility

At December 31, 2006, the Company had an $800.0 million senior secured revolving credit facility with a maturity of August 2010, and a borrowing base of $480.0 million (Credit Facility). In February 2007, in conjunction with the Stallion acquisition and two acquisitions in West Virginia (see Note 2) the Company amended its Credit Facility, increasing the borrowing base to $725.0 million. In connection with this amendment, in the first quarter of 2007, the Company paid fees of approximately $1.5 million, which will be amortized over the remaining term of the Credit Facility, and wrote-off deferred financing fees of approximately $0.5 million.

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. Our obligations under the Credit Facility are secured by mortgages on our oil and gas properties as well as a pledge of all ownership interests in our operating subsidiaries. We are required to maintain the mortgages on properties representing at least 80% of our oil and gas properties. Additionally, the obligations under the Credit Facility are guaranteed by all of our operating subsidiaries and may be guaranteed by any future subsidiaries.

At our election, interest on the Credit Facility is determined by reference to LIBOR plus an applicable margin between 1.00% and 1.75% per annum; or a domestic bank rate plus an applicable margin between 0.00% and 0.25% per annum. LIBOR margins increased by 0.25% during the term of the Subordinated Bridge Loan, which was repaid in October 2006. Interest is payable quarterly for domestic bank rate loans and at the applicable maturity date for LIBOR loans.

The Credit Facility contains various covenants that limit the Company s ability to incur additional indebtedness, make acquisitions or certain capital expenditures; make distributions other than from available cash; merge or consolidate; and engage in certain asset dispositions. The Credit Facility also contains covenants that, among other things, require us to maintain the following financial ratios:

- consolidated net income plus interest expense, income taxes, depreciation, depletion, amortization and other similar changes, minus all non-cash income added to consolidated net income, and giving pro forma effect to any acquisitions or capital expenditures, to interest expense of not less than 2.5 to 1.0

- consolidated current assets, including the unused amount of the total commitments, to consolidated current liabilities of not less than 1.0 to 1.0, excluding non-cash assets and liabilities under SFAS 133, which includes the current portion of oil and gas and interest rate derivatives

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LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The Credit Facility does not contain a minimum debt to equity ratio requirement. The Company is in compliance with all financial and other covenants of its Credit Facility.

As of December 31, 2006 and 2005, the Credit Facility consisted of the following:

	December 31, 2006 (in thousands)	2005
Total (1)	$ 425,750	$ 207,113
Less: Current maturities		(113)
	$ 425,750	$ 207,000

(1) Variable rate of 7.125% and 6.110% at December 31, 2006 and 2005, respectively

At December 31, 2006, the Company also had $4.0 million outstanding letters of credit, which reduce its borrowing availability under the Credit Facility. At December 31, 2006, available borrowing under our Credit Facility was $50.2 million.

Total accrued interest on the Credit Facility was approximately $2.1 million at December 31, 2006. Total accrued interest on the prior credit facility was approximately $1.1 million at December 31, 2005. The Company repaid $53.3 million of borrowings under its Credit Facility in October 2006 (see Note 4).

Subordinated Bridge Loan

In August 2006, in order to fund a portion of the acquisitions of Blacksand and the Kaiser-Francis Assets, we entered into a $250.0 million subordinated bridge loan (Subordinated Bridge Loan) with a termination of August 1, 2007. At our election, interest was determined by reference to LIBOR plus an applicable margin of 4.00% per annum; or a domestic bank rate plus an applicable margin of 2.50% per annum. In October 2006, all proceeds from the Class B Private Placement (see Note 4) were used to repay in full the Company s $250.0 million Subordinated Bridge Loan. In connection with the repayment of the Subordinated Bridge Loan, the Company wrote off approximately $2.7 million of deferred financing fees, which was recognized as expense in the fourth quarter of 2006.

Subordinated Term Loan

During 2005, the Company had a $60.0 million second lien senior subordinated term loan. The borrowings under the subordinated term loan were used to fund a portion of the purchase price for the acquisition of oil and gas properties from Exploration Partners. The outstanding balance was paid in full in 2006, with proceeds from our IPO. Total accrued interest on this loan was approximately $0.4 million at December 31, 2005.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

(9) Long-term Notes Payable

The Company has the following long-term notes payable outstanding:

	December 31, 2006 (in thousands)	2005
Note payable to a bank with an interest rate of 6.14%, payable in monthly installments of $3 including interest, through September 2024. The note is secured by an office building.	$ 372	$ 387
Various notes for the purchase of vehicles and equipment, payable in monthly installments totaling approximately $88 and $11 as of December 31, 2006 and 2005, respectively, including interest. The interest rates range from 3.9%-9.11%. The notes are secured by the vehicles purchased and expire at various dates from 2008 through 2011. (1)	2,989	421
	3,361	808
Less current portion	(874)	(113)
	$ 2,487	$ 695

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(1) At December 31, 2006, includes approximately $1.0 million of notes payable on which interest was imputed at 7.0%.

As of December 31, 2006, maturities on the aforementioned long-term notes payable were as follows:

	(in thousands)
2007	$ 874
2008	870
2009	641
2010	446
2011	229
Thereafter	301
	$ 3,361

(10) Interest Rate Swaps

We have periodically entered into interest rate swap agreements to minimize the effect of fluctuations in interest rates. We are required to pay our counterparties the difference between and the fixed rate in the contract and the actual rate if the actual rate is lower than the fixed rate and conversely, our counterparties are required to pay us if the actual rate is higher than the fixed rate in the contract. We did not designate the interest rate swap agreements we entered into as cash flow hedges under SFAS 133; therefore, the changes in fair value of these instruments were recorded in our current earnings. These amounts are non-cash gains or losses.

The following summarizes the Company s interest rate swaps outstanding:

	December 31, 2006 (in thousands)	2005
Long-term liability, interest rate swaps	$ 423	$ 663
Less current asset	(44)	(202)
	$ 379	$ 461

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Unrealized gains (losses) due to the change in the fair value of approximately $82,000 in 2006, $1.0 million in 2005 and $(1.3) million in 2004 are recorded in interest and financing expense in the consolidated statements of operations.

The following presents the interest rate swaps entered into during the year ended December 31, 2004 (the Company has not entered into any additional interest rate swaps):

	Notional Amount (in thousands)
Interest rate, 5.79%, settles quarterly in 2008	$ 50,000
Interest rate, 5.30% , settles quarterly in 2007	$ 50,000
Interest rate, 4.42%, settled quarterly in 2006	$ 20,000
Interest rate, 3.08%, settled quarterly in 2005	$ 20,000

(11) Asset Retirement Obligation

The Company accounts for asset retirement obligations in accordance with SFAS 143, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method over the asset s useful life. The asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells.

At December 31, 2006 and 2005, there were no assets legally restricted for purposes of settling asset retirement obligations. Additional retirement obligations increase the liability associated with new oil and gas wells and other facilities as these obligations are incurred. Under certain operating agreements, the Company withholds funds from the working interest owners for future plugging costs. These liabilities from the amounts withheld are included in the total asset retirement obligation on the accompanying consolidated balance sheets.

The following table reflects the changes in the asset retirement obligation during the years presented:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Carrying amount of asset retirement obligation at beginning of year	$ 5,443	$ 3,857	$ 2,053
Liabilities added during the current year related to acquisitions or drilling of additional wells	2,806	1,390	1,711
Cash withheld during the current year from unrelated third parties who own working interests	31	24	19
Current year accretion expense	314	172	74
Carrying amount of asset retirement obligation at end of year	$ 8,594	$ 5,443	$ 3,857

The discount rate used in calculating the asset retirement obligation was 7.0%, 5.8% and 4.3% in 2006, 2005 and 2004, respectively. These rates approximate the Company s credit adjusted risk-free rates. See Note 8.

(12) Commitments and Contingencies

The Company would be exposed to oil and gas price fluctuations on underlying sale contracts should the counterparties to the Company s derivative instruments or the counterparties to the Company s oil and gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses during the years ended December 31, 2006, 2005 or 2004.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

From time to time the Company is a party to various legal proceedings or is subject to industry rulings that could bring rise to claims in the ordinary course of business. The Company is not currently a party to any litigation or pending claims that it believes would have a materially adverse effect on the Company s business, financial condition, results of operations or liquidity.

(13) Related Party Transactions

For the year ended December 31, 2006, the Company made payments of approximately $0.4 million to a company owned by one of our senior executives. The payments reflect reimbursement for maintenance and hourly usage fees for business use of an aircraft that was partially owned by the senior executive. These costs are included in general and administrative expense on the consolidated statement of operations. The fees and expenses associated with the reimbursements were consummated on terms equivalent to those that prevail in arm s-length transactions. In the third quarter of 2006, the Company purchased an ownership interest in an airplane for corporate travel from a third party; therefore, these reimbursements will not be ongoing. Simultaneous with this transaction, the senior executive was able to fully liquidate the investment in the aircraft owned by his company.

Under the terms of its limited liability company agreement, during 2005 Linn paid to Quantum Energy Partners, the majority member, a fee of 2.0% of each capital contribution made to the Company by Quantum Energy Partners. Management believes the 2.0% fee was fair value. The 2.0% fee was initially negotiated on an arms-length basis among unrelated third parties. Fees paid during the year ended December 31, 2005 were approximately $0.3 million. No such fees were paid in other years. The payments were recognized as a return of capital on the consolidated statement of unitholders capital.

Mr. Eric P. Linn is President of Mid Atlantic Well Service, Inc., a wholly owned subsidiary of Linn. Mr. Linn s 2007 annual base salary is $175,000 and he is provided with use of a Company vehicle. Mr. Linn is the brother of the Company s Chairman, President and Chief Executive Officer, Michael C. Linn.

(14) Earnings Per Unit

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. The Company uses the treasury stock method to determine the dilutive effect. At December 31, 2006, the Company had two classes of units outstanding, (i) units representing limited liability company interests (units) listed on The NASDAQ Global Market under the symbol LINE and (ii) Class B units. See Note 4 for details regarding the Class B units.

In accordance with SFAS No. 128, *Earnings Per Share* (SFAS 128) dual presentation of basic and diluted earnings per unit has been presented in the consolidated statements of operations for each class of units issued and outstanding at December 31, 2006, units and Class B units. Net income per unit is allocated to the units and the Class B units on an equal basis. Certain existing holders of Linn units totaling over 50% committed in advance to vote a at unitholder meeting in favor of the conversion of class B units to units and the Class B units were converted to units on a one-for-one basis in January 2007 (see Note 4); therefore, the Class B units share equally with the units in the net income of the Company. Since the Class B units were converted to units in January 2007, they share equally in the February 2007 distributions and all future distributions. The Company made no distributions to Class B unitholders during the period the Class B units were outstanding.

For the periods prior to the Company s IPO, equivalent units were calculated by adjusting pre-IPO members membership interests by the exchange ratio to reflect the exchange of pre-IPO membership interests for post-IPO units and cash immediately prior to completion of the IPO (see Note 3).

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following reconciliation presents the impact on the unit amounts of potential common units and the earnings per unit amounts:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands, except per unit amounts)		
Net income (loss)	$ 79,185	$ (56,351)	$ (4,816)
Weighted average units outstanding:			
Basic units outstanding	28,281	20,518	20,518
Dilutive effect of unit equivalents and Class B units(a)	2,104		
Diluted units outstanding	30,385	20,518	20,518
Weighted average Class B units outstanding:			
Basic Class B units outstanding	1,737		
Dilutive effect of unit equivalents			
Diluted Class B units outstanding	1,737		
Net income (loss) per unit:			
Units - basic	$ 2.64	$ (2.75)	$ (0.23)
Units - diluted	$ 2.61	$ (2.75)	$ (0.23)
Class B units - basic	$ 2.64	$	$
Class B units - diluted	$ 2.61	$	$

(a) Excludes the effect of average anti-dilutive common stock equivalents related to out-of-the-money options and restricted units of 234,016 for the year ended December 31, 2006.

Subsequent to December 31, 2006, the Company granted an aggregate 150,000 unit options to non-employees. These options will be evaluated for inclusion in diluted earnings per unit in accordance with SFAS 128.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

(15) Oil and Gas Derivatives

The Company sells oil and gas in the normal course of its business and utilizes derivative instruments to minimize the variability in forecasted cash flows due to price movements in oil and gas. The Company enters into derivative instruments such as swap contracts and put options to hedge a portion of its forecasted oil and gas sales.

Settled derivatives on gas production for the year ended December 31, 2006 included a volume of 9,262 MMBtu at an average contract price of $9.16. Settled derivatives on oil production for the year ended December 31, 2006 included a volume of 186 MBbls at an average contract price of $76.87. Currently, we use fixed price swaps and puts to manage commodity prices. The oil and gas transactions are settled based upon the closing NYMEX future price of gas on the settlement date, which occurs on the third day of the production month proceeding the production month. The oil transactions are settled based upon the average daily NYMEX price of light oil and settlement occurs on the final day of the production month.

The following tables summarize open positions as of December 31, 2006 and represents, as of such date, our derivatives in place through December 31, 2011, on annual production volumes:

	Year 2007	**Year 2008**	**Year 2009**
Gas Positions			
Fixed Price Swaps:			
Hedged Volume (MMBtu)	8,203	10,264	8,005
Average Price ($/MMBtu)	$ 8.72	$ 8.37	$ 7.89
Puts:			
Hedged Volume (MMBtu)	3,018	2,013	
Average Price ($/MMBtu)	$ 9.22	$ 9.50	$
Total:			
Hedged Volume (MMBtu)	11,221	12,277	8,005
Average Price ($/MMBtu)	$ 8.86	$ 8.56	$ 7.89

	Year 2007	**Year 2008**	**Year 2009**	**Year 2010**	**Year 2011**
Oil Positions					
Fixed Price Swaps:					
Hedged Volume (MBbls)	500	500	500	500	
Average Price ($/Bbl)	$ 75.83	$ 75.83	$ 75.83	$ 75.83	$
Puts:					
Hedged Volume (MBbls)	1,300	1,400	1,400	1,400	1,200
Average Price ($/Bbl)	$ 66.54	$ 66.43	$ 66.43	$ 66.43	$ 65.00
Total:					
Hedged Volume (MBbls)	1,800	1,900	1,900	1,900	1,200
Average Price ($/Bbl)	$ 69.12	$ 68.90	$ 68.90	$ 68.90	$ 65.00

The oil and gas derivatives are not designated as cash flow hedges under SFAS 133 and, accordingly, the changes in fair value are recorded in current period earnings.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the outstanding notional amounts and maximum number of months outstanding of our derivatives on annual production volumes:

	December 31, 2006	2005
Outstanding notional amounts of gas hedges (MMBtu)	31,503	28,069
Maximum number of months gas hedges outstanding	35	48
Outstanding notional amounts of oil hedges (MBbls)	8,700	
Maximum number of months oil hedges outstanding	60	

By using derivative instruments to hedge exposures to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company minimizes the credit risk in derivative instruments by entering into transactions with high-quality counterparties.

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.

(16) Operating Leases

The Company leases office space and equipment under lease agreements expiring on various dates through 2015. For the years ended December 31, 2006, 2005 and 2004, the Company recognized expense under operating leases of approximately $0.5 million, $0.4 million and $0.2 million, respectively. The Company accounts for leases with escalation clauses and rent holidays on a straight-line basis in accordance with SFAS No. 13, *Accounting for Leases.*

As of December 31, 2006, future minimum lease payments were as follows:

	(in thousands)
2007	$ 825
2008	1,039
2009	1,065
2010	1,101
2011	1,131
Thereafter	3,676
	$ 8,837

(17) Income Taxes

The Company is treated as a partnership for federal and state income tax purposes. As such, it is not a taxable entity and does not directly pay federal and state income tax. Its taxable income or loss, which may vary substantially from the net income or net loss reported in the consolidated statements of operations, is includable in the federal and state income tax returns of each unitholder. Accordingly, no recognition has been given to federal and state income taxes for the operations of the Company except as described below. The aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each unitholder s tax attributes in the Company.

On June 1, 2005, Linn Operating, LLC (Linn Operating) was converted to a Subchapter C-corporation. Additionally, on October 12, 2005, the Company incorporated Mid Atlantic Well Service, Inc. (Mid Atlantic). Prior to June 1, 2005, the Company and its subsidiaries were structured as limited liability companies treated as partnerships or disregarded entities for federal income tax purposes.

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The income tax provision attributable to the Company s Subchapter C-corporation subsidiaries losses before income taxes consisted of the following:

	Year Ended December 31, 2006 Current (in thousands)	2006 Deferred	2006 Total	2005 Current	2005 Deferred	2005 Total
Federal	$	$ 2,999	$ 2,999	$	$ (57)	$ (57)
State	(32)	435	403		(17)	(17)
Income tax benefit (provision)	$ (32)	$ 3,434	$ 3,402	$	$ (74)	$ (74)

As of December 31, 2006 and 2005, the Company s taxable entities had approximately $10.1 million and $0.5 million, respectively, of net operating loss carryforwards for federal income tax purposes, which will begin expiring in 2025.

Income tax expense differed from amounts computed by applying the federal income tax rate of 35% to pre tax income as a result of the following:

	Year Ended December 31, 2006 (in thousands)		2005	
Federal statutory rate	$ (26,174)	(35.0)%	$ 19,134	34.0 %
State, net of federal tax benefit	307	0.4 %	(12)	(0.0)%
(Income) loss from non-taxable entities	37,874	50.6 %	(19,168)	(34.0)%
Non-deductible compensation	(6,803)	(9.1)%		
Other items	(1,802)	(2.4)%	(28)	(0.1)%
Income tax benefit (provision)/effective rate	$ 3,402	4.6 %	$ (74)	(0.1)%

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

	December 31, 2006 (in thousands)	2005
Deferred tax assets:		
Net operating loss carryforwards	$ 4,227	$ 3
Unit-based compensation	1,766	
Other	358	24
Valuation allowance	(2,318)	40
Total deferred tax assets	4,033	67
Deferred tax liabilities:		
Property and equipment principally due to differences in depreciation	(673)	(141)
Total deferred tax liabilities	(673)	(141)
Net deferred tax assets (liabilities)	$ 3,360	$ (74)

LINN ENERGY, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

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

	2006	2005
	(in thousands)	
Deferred tax asset	$ 4,033	$ 67
Deferred tax liability	(673)	(141)
Net deferred tax assets (liabilities)	$ 3,360	$ (74)

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes it is more likely than not that we will realize the benefits of these deductible differences at December 31, 2006. The amount of the deferred tax asset considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

LINN ENERGY, LLC
SUPPLEMENTARY OIL AND GAS DATA (Unaudited)

(A) Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Costs incurred in oil and gas property acquisition and development are presented below:

	Year Ended December 31,		
	2006	**2005**	**2004**
	(in thousands)		
Property acquisition costs:			
Proved (1)	$ 450,232	$ 118,489	$ 27,271
Unproved	4,062	579	2,940
Development costs (1)	47,112	27,145	14,719
Gas compression plant and pipelines	15,232	4,043	1,537
Company s share of equity investee s costs of property acquisition, exploration, and development			15

(1) Includes a reclassification of approximately $112.0 million and $16.8 million from development costs to proved acquisition costs for the years ended December 31, 2005 and 2004, respectively, in order to conform to current year presentation.

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells and to provide facilities to extract, treat and gather oil and gas.

The Company capitalizes costs related to drilling and development of oil and gas properties for specific activities related to drilling its wells, which included site preparation, drilling labor, meter installation, pipeline connection and site reclamation. Such costs totaled approximately $8.5 million, $1.6 million and $0.2 million during the years ended December 31, 2006, 2005 and 2004, respectively.

Additionally, development costs include the asset retirement obligation for future plugging costs. See Note 11 in Notes to Consolidated Financial Statements.

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

(B) Oil and Gas Capitalized Costs

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

	December 31,	
	2006	2005
	(in thousands)	
Unproved properties	$ 8,624	$ 4,562
Proved properties:		
Leasehold, equipment and drilling	737,202	239,858
Gas compression plant and pipelines	20,812	5,580
	766,638	250,000
Less accumulated depletion, depreciation and amortization	(33,349)	(10,707)
Net capitalized costs	$ 733,289	$ 239,293

(C) Results of Oil and Gas Producing Activities

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

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Revenues:			
Oil and gas sales, excluding natural gas marketing revenues	$ 80,393	$ 44,645	$ 19,502
Gain (loss) on oil and gas derivatives	103,308	(76,193)	(11,004)
Net oil and gas sales	183,701	(31,548)	8,498
Expenses:			
Production costs	18,099	7,356	4,756
Depreciation, depletion and amortization	22,714	7,022	3,521
Total expenses	40,813	14,378	8,277
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	$ 142,888	$ (45,926)	$ 221
Company s share of equity method investee s results of operations for producing activities.	$	$ (17)	$ (56)

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including such costs as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance and other production taxes. In addition, production costs include administrative expenses applicable to support equipment associated with these activities.

Depreciation, depletion and amortization expense includes those costs associated with capitalized acquisition and development costs and support equipment. For the year ended December 31, 2006, depreciation, depletion and amortization expense also includes approximately $1.0 million of impairments recorded on oil and gas properties (see Note 1 in Notes to Consolidated Financial Statements).

There is no tax provision included in our results of oil and gas producing activities because all of our taxable income or loss is reported by the Company s taxable subsidiaries, which do not own any of the Company s oil and gas interests. See Note 17 in Notes to Consolidated Financial

Statements for additional details about the Company s income taxes

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

(D) Net Proved Oil and Gas Reserves

The proved reserves of oil and gas of the Company have been estimated by an independent petroleum engineering firm, DeGolyer and MacNaughton, at December 31, 2006. Independent petroleum engineering firm, Schlumberger Data and Consulting Services provided the estimated reserves at December 31, 2005 and 2004. These reserve estimates have been prepared in compliance with the SEC rules based on year-end prices. An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below:

	Year Ended December 31, 2006		
	Gas (MMcf)	**Oil (MBbls)**	**Total (MMcfe)**
Proved developed and undeveloped reserves:			
Beginning of year	191,856	226	193,210
Revisions of previous estimates	(37,239)	370	(35,018)
Purchase of minerals in place	84,951	29,784	263,655
Extensions and discoveries	43,037		43,037
Production	(8,599)	(370)	(10,818)
End of year	274,006	30,010	454,066
Proved developed reserves:			
Beginning of year	123,865	226	125,220
End of year	166,007	24,675	314,057

	Year Ended December 31, 2005 Gas (MMcfe)	**2004**
Proved developed and undeveloped reserves:		
Beginning of year	119,760	69,805
Revisions of previous estimates	2,415	755
Purchase of minerals in place	53,976	35,827
Extensions and discoveries	21,898	16,485
Production	(4,839)	(3,112)
End of year	193,210	119,760
Proved developed reserves:		
Beginning of year	74,366	41,760
End of year	125,220	74,366

For the years ended December 31, 2005 and 2004, the above table includes changes in estimated quantities of oil reserves shown in Mcf equivalents at a rate of one barrel per six Mcf. Net oil production included above represents approximately 3% and 2% of total production in 2005 and 2004, respectively.

The 37,239 MMcfe decrease in previous estimate in 2006 was due primarily to the decrease in gas prices. The 2,415 MMcfe and 755 MMcfe increases in revisions of previous estimates in 2005 and 2004, respectively, were due to the increase in gas prices.

Extensions and discoveries of 43,037 MMcfe, 21,898 MMcfe and 16,485 MMcfe in 2006, 2005 and 2004, respectively, are primarily due to the drilling of 159 wells during 2006, 110 wells during 2005 and 90 wells during 2004, which increased the Company s proved undeveloped drilling locations.

The Company made five, three and two acquisitions during 2006, 2005 and 2004, respectively, with total proved reserves of 263,655 MMcfe, 53,976 MMcfe and 35,827 MMcfe, respectively.

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

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

Summarized in the following table is information for the Company with respect to the standardized measure of discounted future net cash flows relating to proved reserves. Future cash inflows are computed by applying year-end prices relating to the Company s proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. There are no future income tax expenses because the Company is a nontaxable entity (see Note 17 in Notes to Consolidated Financial Statements).

	December 31,		
	2006	2005	2004
	(in thousands)		
Future estimated revenues	$ 3,053,772	$ 2,041,930	$ 840,127
Future estimated production costs	(868,564)	(332,839)	(146,672)
Future estimated development costs	(239,328)	(96,542)	(41,417)
Future net cash flows	1,945,880	1,612,549	652,038
10% annual discount for estimated timing of cash flows	(1,393,620)	(1,060,474)	(437,004)
Standardized measure of discounted future estimated net cash flows	$ 552,260	$ 552,075	$ 215,034

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

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Sales of oil and gas production, net of production costs	$ (62,294)	$ (37,676)	$ (14,829)
Changes in estimated future development costs	(2,173)	55,125	17,341
Net changes in prices and production costs	(536,672)	135,701	4,443
Purchase of minerals in place	508,107	64,361	57,970
Extensions, discoveries, and improved recovery, less related cost	17,872	192,412	26,507
Development costs incurred during the period	47,112	26,406	16,733
Revisions of previous quantity estimates	(10,747)	1,026	3,671
Change in discount	55,208	21,503	12,634
Changes in production rates and other	(16,228)	(121,817)	(35,778)
	$ 185	$ 337,041	$ 88,692

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

LINN ENERGY, LLC
SUPPLEMENTARY QUARTERLY DATA (Unaudited)

(A) Quarterly Financial Data

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2006				
Oil and gas sales	$ 16,375	$ 13,529	$ 23,506	$ 26,983
Gain on oil and gas derivatives	24,246	12,895	57,396	8,771
Total revenues	42,128	27,974	82,257	38,699
Operating expenses	2,994	2,933	4,845	7,327
General and administrative expenses	9,470	6,928	6,536	17,059
Net income (loss)	$ 21,977	$ 10,239	$ 53,057	$ (6,088)
Net income (loss) per unit:				
Units - basic	$ 0.84	$ 0.37	$ 1.92	$ (0.16)
Units - diluted	$ 0.84	$ 0.36	$ 1.89	$ (0.15)
Class B units - basic	$	$	$	$ (0.16)
Class B units - diluted	$	$	$	$ (0.15)

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(in thousands, except per unit amounts)			
2005				
Oil and gas sales	$ 6,146	$ 7,855	$ 10,407	$ 20,237
Loss on oil and gas derivatives	(15,155)	(6,992)	(50,463)	(3,583)
Total revenues	(8,121)	1,582	(38,418)	18,476
Operating expenses	1,817	1,488	1,386	2,665
General and administrative expenses	478	670	1,197	987
Net income (loss)	$ (12,399)	$ (5,276)	$ (45,590)	$ 6,914
Net income (loss) per unit - basic	$ (0.60)	$ (0.26)	$ (2.22)	$ 0.34
Net income (loss) per unit - diluted	$ (0.60)	$ (0.26)	$ (2.22)	$ 0.34

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

None.

Item 9A. Controls and Procedures

(a) Evaluation of disclosure controls and procedures

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

We carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report.

Due to the material weakness described below, our Chief Executive Officer and Chief Financial Officer continue to conclude that our disclosure controls and procedures were not effective as of December 31, 2006. As noted below, we believe we have taken the necessary steps to address the matters related to the material weakness. However, before concluding that the material weakness has been remediated, management believes that the new internal controls should be implemented and operational for a sufficient period of time to demonstrate that the controls are operating effectively. We believe our consolidated financial statements included in this Annual Report on Form 10-K fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in accordance with United States generally accepted accounting principles.

Material weakness in internal control. In connection with the preparation of the Company s Annual Report on Form 10-K for the year ended December 31, 2005 (2005 10-K), an evaluation was performed under the supervision and with the participation of the Company s management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures as defined in Rule 13a-15(e) and Rule 15d-15(e) under the Exchange Act. The Company concluded that the disclosure controls and procedures were not effective as of December 31, 2005.

Specifically, the Company lacked (i) personnel with sufficient technical accounting and financial reporting expertise, (ii) adequate review controls over account reconciliations and account analyses, (iii) policies and procedures in place to determine and document the appropriate application of accounting principles and (iv) policies and procedures requiring a detailed and comprehensive review of the underlying information supporting the amounts included in the annual and interim consolidated financial statements and disclosures. We undertook numerous remedial actions, as described below, to enhance controls.

Remediation activities. During 2006, Company management has taken the following steps to strengthen internal control over financial reporting.

1. We recruited an experienced accounting team with over 130 combined years of experience in oil and gas accounting and financial reporting.

2. We utilized outside consultants with extensive oil and gas financial reporting experience and augmented our accounting resources to assist with required filings and documentation of reconciliations and procedures.

3. Accounting and reporting position papers were developed for critical accounting policies involving judgment or application of complex accounting standards.

Item 9A. Controls and Procedures - Continued

4. We performed additional analysis and other post-closing procedures to enable the preparation of accurate consolidated financial statements, including all required disclosures. In addition, we implemented certain review and monitoring controls over account reconciliations, and analysis and post-closing procedures.

5. We developed and implemented a process for determining the effective accounting date for an oil and gas property acquisition and formalized procedures necessary to appropriately account for future acquisitions.

6. We implemented the use of disclosure checklists addressing the disclosure requirements under GAAP as well as the incremental financial and nonfinancial information required by SEC regulations.

7. We provided extensive training on our accounting software system to both new and established accounting personnel.

We believe we have taken the necessary steps to address the matters related to the material weakness described above. However, before concluding that the material weakness has been remediated, management believes that the new internal controls should be implemented and operational for a sufficient period of time to demonstrate that the controls are operating effectively.

(b) Changes and remediation in the Company s internal control over financial reporting

In response to the material weakness noted in 4(a) above, during the three months ended December 31, 2006, Company management has taken the following remedial actions (i) hired additional experienced personnel with technical accounting, financial reporting and oil and gas experience, (ii) provided additional training on our accounting software system to both new and established accounting personnel and (iii) continued to perform and to enhance additional analysis and other post-closing procedures, including certain review and monitoring controls over account reconciliation. These three items constitute the changes in our internal control over financial reporting, as defined in Rule 13(a)-15(f) under the Exchange Act, during the three months ended December 31, 2006, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Further as previously reported, we expect to continue to make changes in our internal control over financial reporting during the periods prior to December 31, 2007, in connection with our compliance efforts under Section 404 of the Sarbanes-Oxley Act of 2002. As such, we will continue to assess the adequacy of our internal control over financial reporting, remediate any control weaknesses that may be identified, validate through testing that controls are functioning as designed and implement a continuous reporting and improvement process for internal control over financial reporting.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

A list of our executive officers and biographical information appears in Part I. Item 1. Business in this Form 10-K. Information about our Directors may be found under the caption Election of Directors of our Proxy Statement for the Annual Meeting of Unitholders to be held June 19, 2007 (the 2007 Proxy Statement). That information is incorporated herein by reference.

The information in the 2007 Proxy Statement set forth under the caption Section 16(a) Beneficial Ownership Reporting Compliance is incorporated herein by reference.

We have adopted the Linn Energy, LLC Code of Ethics for Chief Executive Officer and Senior Financial Officers (the finance code of ethics), a code of ethics that applies to our Chief Executive Officer, Chief Financial Officer and other finance organization executives. The finance code of ethics is publicly available on our website at www.linnenergy.com. If we make any substantive amendments to the finance code of ethics or grant any waiver, including any implicit waiver, from a provision of the code to our Chief Executive Officer, Chief Financial Officer or any other finance organization executive, we will disclose the nature of such amendment or waiver on that website or in a Current Report on Form 8-K.

Item 11. Executive Compensation

Information required by this item is incorporated herein by reference to the 2007 Proxy Statement.

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

Information required by this item is incorporated herein by reference to the 2007 Proxy Statement.

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

Information required by this item is incorporated herein by reference to the 2007 Proxy Statement.

Item 14. Principal Accounting Fees and Services

Information required by this item is incorporated herein by reference to the 2007 Proxy Statement.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a) 2. Financial Statement Schedules:

See Note 1 in Notes to Consolidated Financial Statements for Valuation and Qualifying Accounts and Allowances.

All other schedules are omitted for the reason that they are not required or the information is otherwise supplied under Part II. Item 8.

(a) 3. Exhibits Filed:

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

SIGNATURES

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

	LINN ENERGY, LLC	
Date: March 30, 2007	By:	/s/ MICHAEL C. LINN Michael C. Linn *Chairman, President and Chief Executive Officer*
Date: March 30, 2007	By:	/s/ LISA D. ANDERSON Lisa D. Anderson *Senior Vice President and Chief Accounting Officer*

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

Signature	Title	Date
/s/ MICHAEL C. LINN Michael C. Linn	Chairman, President and Chief Executive Officer (Principal Executive Officer)	March 30, 2007
/s/ KOLJA ROCKOV Kolja Rockov	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 30, 2007
/s/ LISA D. ANDERSON Lisa D. Anderson	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 30, 2007
/s/ GEORGE A. ALCORN George A. Alcorn	Independent Director	March 30, 2007
/s/ TERRENCE S. JACOBS Terrence S. Jacobs	Independent Director	March 30, 2007
/s/ ALAN L. SMITH Alan L. Smith	Director	March 30, 2007
/s/ JEFFREY C. SWOVELAND Jeffrey C. Swoveland	Independent Director	March 30, 2007

INDEX TO EXHIBITS

Exhibit Number	Description
2.1	Purchase and Sale Agreement by and among Linn Energy, LLC and Blacksand Energy, LLC, dated July 19, 2006 (incorporated herein by reference to Exhibit 2.1 to our Current Report on Form 8-K filed on July 25, 2006)
2.2	Purchase and Sale Agreement between Linn Energy, LLC and Kaiser-Francis Oil Company dated July 21, 2006 (incorporated herein by reference to Exhibit 2.2 to our Current Report on Form 8-K filed on July 25, 2006)
2.3	Purchase and Sale Agreement dated December 13, 2006, by and between Cavallo Energy LP, a Delaware limited partnership, acting through its general partner, Stallion Energy LLC, a Delaware limited liability company and Linn Energy, LLC, a Delaware limited liability company (Large Package Agreement) (incorporated herein by reference to Exhibit 2.1 to our Current Report on Form 8-K filed on February 5, 2007)
2.4	Purchase and Sale Agreement dated December 13, 2006, by and between Cavallo Energy LP, a Delaware limited partnership, acting through its general partner, Stallion Energy LLC, a Delaware limited liability company and Linn Energy, LLC, a Delaware limited liability company (Small Package Agreement) (incorporated herein by reference to Exhibit 2.2 to our Current Report on Form 8-K filed on February 5, 2007)
2.5	Gathering System Purchase Agreement dated February 1, 2007, by and between Cavallo Gathering Company LLC, a Texas limited liability company, and Penn West Pipeline, LLC, a Delaware limited liability company (incorporated herein by reference to Exhibit 2.3 to our Current Report on Form 8-K filed on February 5, 2007)
3.1	Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.1 to our Registration Statement on Form S-1 (File No. 333-125501) filed by Linn Energy, LLC on June 3, 2005)
3.2	Certificate of Amendment to Certificate of Formation of Linn Energy Holdings, LLC (now Linn Energy, LLC) (incorporated herein by reference to Exhibit 3.2 to our Form S-1 filed on June 3, 2005)
3.3	Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated January 19, 2006
3.4	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated October 24, 2006
3.5	Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated February 1, 2007
4.1	Form of specimen unit certificate for the units of Linn Energy, LLC (incorporated herein by reference to Exhibit 4.1 to the Annual Report on our Form 10-K filed on May 31, 2006)
4.2	Form of Class C Unit Certificate (incorporated herein by reference to Exhibit 4.2 to our Current Report on Form 8-K filed on February 5, 2007)
10.1*	Form of Linn Energy, LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.10 to Amendment No. 4 to our Registration Statement on Form S-1 filed on December 14, 2005)
10.2*	First Amendment to Linn Energy, LLC Long-Term Incentive Plan dated January 18, 2007 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on January 19, 2007)
10.3*	Second Amendment to Linn Energy, LLC Long-Term Incentive Plan dated March 21, 2007
10.4*	Form of Executive Unit Option Agreement pursuant to the Linn Energy, LLC Long-Term Incentive Plan
10.5*	Form of Executive Restricted Unit Agreement pursuant to the Linn Energy, LLC Long-Term Incentive Plan
10.6*	Form of Phantom Unit Grant Agreement for Independent Directors pursuant to the Linn Energy, LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on August 9, 2006)

INDEX TO EXHIBITS - Continued

Exhibit Number	**Description**
10.7*	Amended and Restated Employment Agreement, dated effective as of December 14, 2005 between Linn Operating, Inc. and Michael C. Linn (incorporated herein by reference to Exhibit 10.12 to Amendment No. 4 to our Registration Statement on Form S-1 (File No. 333-125501) filed on December 14, 2005)
10.8*	Second Amended and Restated Employment Agreement, dated as of September 15, 2005 between Linn Operating, Inc. and Kolja Rockov (incorporated herein by reference to Exhibit 10.12 to Amendment No. 2 to our Registration Statement on Form S-1 (File No. 333-125501) filed on October 31, 2005)
10.9*	Employment Agreement, dated effective as of December 18, 2006 between Linn Operating, Inc. and Mark E. Ellis (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on November 29, 2006)
10.10*	Employment Agreement, dated effective as of April 3, 2006 between Linn Operating, Inc. and Thomas A. Lopus (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on April 18, 2006)
10.11*	Employment Agreement, dated effective as of July 7, 2006 between Linn Operating, Inc. and Lisa D. Anderson (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on July 13, 2006)
10.12*	Second Amended and Restated Credit Agreement dated as of August 1, 2006 among Linn Energy, LLC as Borrower, BNP Paribas, as Administrative Agent, Royal Bank of Canada, as Syndication Agent, Societe Generale, Comerica Bank and Citibank Texas, N.A. as Co-Documentation Agents and the Lenders Party thereto (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on August 7, 2006)
10.13	First Amendment to Second Amended and Restated Credit Agreement dated as of February 1, 2007, among Linn Energy, LLC, as borrower, BNP Paribas, as administrative agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.4 to our Current Report on Form 8-K filed on February 5, 2007)
10.14	Second Amended and Restated Guaranty and Pledge Agreement dated as of August 1, 2006 made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent (incorporated herein by reference to Exhibit 10.3 to our Current Report on Form 8-K filed on August 7, 2006)
10.15	Second Lien Guaranty and Pledge Agreement dated as of August 1, 2006 made by Linn Energy, LLC and each of the other Obligors in favor of BNP Paribas, as Administrative Agent (incorporated herein by reference to Exhibit 10.4 to our Current Report on Form 8-K filed on August 7, 2006)
10.16	Class B Unit and Unit Purchase Agreement, dated as of October 24, 2006 by and between Linn Energy, LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on October 25, 2006)
10.17	Registration Rights Agreement dated as of October 24, 2006 by and among Linn Energy, LLC and the Purchasers named therein (incorporated herein by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on October 25, 2006)
10.18	Class C Unit and Unit Purchase Agreement, dated as of February 1, 2007 by and among the Company and the Purchasers named therein (incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on February 5, 2007)
10.19	Registration Rights Agreement dated February 1, 2007, by and among the Company and the Purchasers named therein (incorporated herein by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on February 5, 2007)
10.20	Transition Services Agreement Dated February 1, 2007, by and between Stallion Energy LLC, a Delaware limited liability company, and Linn Energy, LLC, a Delaware limited liability company, Linn Energy Holdings, LLC, a Delaware limited liability company, Linn Operating, Inc., a Delaware corporation and Penn West Pipeline, LLC, a Texas limited liability company (incorporated herein by reference to Exhibit 10.3 to our Current Report on Form 8-K filed on February 5, 2007)
21.1	Significant Subsidiaries of Linn Energy, LLC
23.1	Consent of KPMG LLP for Linn Energy, LLC
23.2	Consent of DeGolyer and MacNaughton Data and Consulting Services
23.3	Consent of Schlumberger Technology Corporation

INDEX TO EXHIBITS - Continued

Exhibit Number	Description
31.1	Section 302 Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC
31.2	Section 302 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC
32.1	Section 906 Certification of Michael C. Linn, Chairman, President and Chief Executive Officer of Linn Energy, LLC
32.2	Section 906 Certification of Kolja Rockov, Executive Vice President and Chief Financial Officer of Linn Energy, LLC

Filed herewith.

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