LINN ENERGY, LLC
Form 10-Q
May 14, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

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

For the Quarterly Period Ended March 31, 2007

OR

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

for the transition period from to

Commission File Number: 000-51719

LINN ENERGY, LLC

(Exact name of registrant as specified in its charter)

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

(281) 605-4100

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

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

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

As of April 30, 2007, there were 57,798,965 units outstanding.

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GLOSSARY OF TERMS

As commonly used in the oil and gas industry and as used in this Quarterly Report on Form10-Q, the following terms have the following meanings:

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

Bcf. One billion cubic feet.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of 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.

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

NYMEX. The New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

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 FINANCIAL INFORMATION

Item 1. Financial Statements

LINN ENERGY, LLC

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2007 (Unaudited) (in thousands)	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 976	$ 6,595
Receivables trade, net	23,414	19,124
Inventory	745	578
Current portion of derivatives	24,513	37,817
Current portion of deferred tax assets, net		3,344
Other current assets	2,723	2,218
Total current assets	52,371	69,676
Oil and gas properties and related equipment (successful efforts method)	1,253,363	766,638
Less accumulated depreciation, depletion and amortization	(44,188)	(33,349)
	1,209,175	733,289
Property and equipment, net	24,067	20,754
Other assets:		
Long-term portion of derivatives	86,443	70,435
Deposit for oil and gas properties		20,086
Deferred financing fees and other assets, net	2,897	2,068
	89,340	92,589
Total assets	$ 1,374,953	$ 916,308

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2007 (Unaudited) (in thousands, except unit amounts)	December 31, 2006
Liabilities and Unitholders Capital		
Current liabilities:		
Current portion of long-term notes payable	$ 871	$ 873
Accounts payable and accrued expenses	14,369	12,506
Current portion of derivatives	6,078	462
Revenue distribution	1,620	1,839
Accrued interest payable	2,441	2,084
Gas purchases payable	101	253
Total current liabilities	25,480	18,017
Long-term liabilities:		
Notes payable	2,250	2,487
Credit facility	596,750	425,750
Asset retirement obligation	14,877	8,594
Derivatives	24,785	9,934
Other long-term liabilities	968	572
Total long-term liabilities	639,630	447,337
Total liabilities	665,110	465,354
Unitholders capital:		
50,303,019 units and 33,617,187 units issued and outstanding at March 31, 2007 and December 31, 2006, respectively	577,855	246,034
9,185,965 Class B units issued and outstanding at December 31, 2006		188,590
7,465,946 Class C units issued and outstanding at March 31, 2007	183,505	
Accumulated income (loss)	(51,517)	16,330
	709,843	450,954
Total liabilities and unitholders capital	$ 1,374,953	$ 916,308

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

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LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended March 31, 2007	2006
	(in thousands, except per unit amounts)	
Revenues:		
Oil, gas and natural gas liquid sales	$ 39,204	$ 16,375
Gain (loss) on oil and gas derivatives	(60,441)	24,246
Natural gas marketing revenues	1,778	1,218
Other revenues	2,090	289
	(17,369)	42,128
Expenses:		
Operating expenses	12,456	2,994
Natural gas marketing expenses	1,347	983
General and administrative expenses	10,621	9,470
Depreciation, depletion and amortization	11,851	3,700
	36,275	17,147
	(53,644)	24,981
Other income and (expenses):		
Interest income	146	146
Interest expense, net of amounts capitalized	(9,913)	(2,639)
Write-off of deferred financing fees and other	(804)	(392)
	(10,571)	(2,885)
Income (loss) before income taxes	(64,215)	22,096
Income tax provision	(3,632)	(119)
Net income (loss)	$ (67,847)	$ 21,977
Net income (loss) per unit:		
Units basic	$ (1.35)	$ 0.84
Units diluted	$ (1.35)	$ 0.84
Class C units basic	$ (1.35)	$
Class C units diluted	$ (1.35)	$
Weighted average units outstanding:		
Units basic	45,456	26,273
Units diluted	45,456	26,273
Class C units basic	4,894	
Class C units diluted	4,894	
Distributions declared per unit	$ 0.52	$

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENT OF UNITHOLDERS CAPITAL

(Unaudited)

	Three Months Ended March 31, 2007	2006
	(in thousands)	
Unitholders capital:		
Balance, beginning of period	$ 434,624	$ 16,024
Sale of units, net of offering expense of $4,339		225,139
Sale of private placement units, net of expense of $6,860	353,140	
Cancellation of member interests		(100,778)
Cancellation of units	(7,399)	
Distribution to members	(22,745)	
Unit-based compensation expense	3,258	5,680
Unit warrant expense	482	
Balance, end of period	761,360	146,065
Accumulated income (loss):		
Balance, beginning of period	16,330	(62,855)
Net income (loss)	(67,847)	21,977
Balance, end of period	(51,517)	(40,878)
Treasury units (at cost):		
Balance, beginning of period		
Purchase of units	(7,399)	
Sale of units		13,671
Redemption of member interests		(114,449)
Cancellation of member interests		100,778
Cancellation of units	7,399	
Balance, end of period		
Total unitholders capital	$ 709,843	$ 105,187

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31, 2007	2006
	(in thousands)	
Cash flow from operating activities:		
Net income (loss)	$ (67,847)	$ 21,977
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	11,851	3,700
Amortization and write-off of deferred financing fees and other	718	582
Gain on sale of assets	(946)	
Accretion of asset retirement obligation	110	58
Unit-based compensation and unit warrant expense	3,740	5,680
Deferred income tax	3,501	
Mark-to-market on oil and gas and interest rate derivatives:		
Total (gains) losses	60,518	(24,653)
Realized gains	6,447	651
Premiums paid for oil and gas derivatives	(52,992)	
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(3,923)	8,126
Increase in inventory and other assets	(672)	(992)
Decrease in derivatives	3,766	
Decrease in accounts payable and accrued expenses	(2,428)	(4,344)
Increase (decrease) in accrued interest payable	357	(489)
Decrease in revenue distribution	(219)	(4,562)
Decrease in gas purchases payable	(152)	(447)
Increase in other liabilities	282	113
Net cash provided by (used in) operating activities	(37,889)	5,400
Cash flow from investing activities:		
Acquisition of oil and gas properties	(440,418)	(17,640)
Development of oil and gas properties	(10,378)	(4,144)
Change in payable related to investing activities	(8,337)	3,024
Purchases of property and equipment	(3,284)	(747)
Proceeds from sale of assets	2,492	14
Net cash used in investing activities	(459,925)	(19,493)
Cash flow from financing activities:		
Proceeds from sale of units	360,000	243,149
Redemption and cancellation of units	(7,399)	(114,449)
Principal payments on notes payable	(239)	(60,056)
Proceeds from credit facility	171,000	13,000
Payments on credit facility		(62,000)
Distribution to members	(22,745)	
Offering costs	(6,860)	(807)
Financing fees	(1,562)	95
Net cash provided by financing activities	492,195	18,932
Net increase (decrease) in cash	(5,619)	4,839
Cash and cash equivalents:		
Beginning	6,595	11,041
Ending	$ 976	$ 15,880

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS SUPPLEMENTAL DISCLOSURES

(Unaudited)

	Three Months Ended March 31,			
	2007		2006	
	(in thousands)			
Supplemental disclosure of cash flow information:				
Cash payments for interest	$	9,310	$	3,336
Supplemental disclosures of non-cash investing and financing activities:				
Acquisitions of vehicles and equipment through issuance of notes payable	$		$	1,172
In connection with the purchase of oil and gas properties, liabilities were assumed as follows:				
Fair value of assets acquired	$	450,694	$	17,640
Cash paid		(440,418)		(17,640)
Liabilities assumed	$	10,276	$	

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

LINN ENERGY, LLC

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

(1) Basis of Presentation

The condensed consolidated financial statements at March 31, 2007, and for the three months ended March 31, 2007 and 2006, are unaudited, but in the opinion of management include all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation of the results for the interim periods. Certain information and note disclosures normally included in annual financial statements prepared in accordance with United States generally accepted accounting principles (GAAP) have been condensed or omitted under Securities and Exchange Commission (SEC) rules and regulations. The results reported in these unaudited condensed consolidated financial statements should not necessarily be taken as indicative of results that may be expected for the entire year.

The financial information included herein should be read in conjunction with the financial statements and notes in our Annual Report on Form 10-K for the year ended December 31, 2006. Certain amounts in the condensed consolidated financial statements and notes thereto have been reclassified to conform to the 2007 financial statement presentation.

(2) Summary of 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) Principles of Consolidation

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

(c) 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 condensed 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, gas and natural gas liquid (NGL) 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, gas and NGL that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. An independent engineering firm 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 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. As a result, the Company s proved reserve estimates developed from such assumptions could materially vary from the ultimate quantities of oil, gas and NGL eventually recovered.

(d) 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.

(e) 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 for recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

(f) Inventory

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

(g) 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. 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* (SFAS 144), 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 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. No impairments were recorded during the three months ended March 31, 2007 or 2006.

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.

(h) Property, Plant and Equipment

Tangible long-lived assets are evaluated in accordance with SFAS 144, 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 as the amount by which the carrying amount of the asset exceeds the fair value of the asset. No impairments were recorded during the three months ended March 31, 2007 or 2006.

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.

(i) 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 March 31, 2007, 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 sheets 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 condensed consolidated statements of operations. See Note 11 for discussion related to derivative financial instruments.

(j) Unit-Based Compensation

Under the provisions of the Linn Energy, LLC Long-Term Incentive Plan, which is administered by the Compensation Committee of the Board of Directors, the Company has granted unit grants, unit options, unit warrants, restricted units, and phantom units to employees, non-employee directors and consultants. 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 ten years. The terms of unit warrants issued to consultants are detailed in Note 13. See Note 13 also for details regarding unit-based compensation granted during the three months ended March 31, 2007.

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

(k) Revenue Distribution

Revenue distribution on the condensed consolidated balance sheets of $1.6 million and $1.8 million represents amounts owed to working interest and royalty interest owners as of March 31, 2007 and December 31, 2006, respectively.

(l) Offering Costs

At December 31, 2006, the line item reported as other current assets on the condensed consolidated balance sheets, includes 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 during the three months ended March 31, 2007.

(m) Deferred Financing Fees

The Company incurred legal and bank fees related to the issuance of debt (see Note 7). The financing fees incurred for the three months ended March 31, 2007 and 2006 were $1.6 million and zero, respectively. These debt issuance costs are amortized over the life of the debt agreement. For the three months ended March 31, 2007 and 2006, amortization expense of $0.2 million and $0.2 million, respectively, is included in interest expense. Deferred financing fees of approximately $0.5 million and $0.4 million were written-off in connection with refinancings during the three months ended March 31, 2007 and 2006, respectively.

(n) 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 March 31, 2007 and December 31, 2006.

(o) 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 expenses. For the three months ended March 31, 2007 and 2006, the operating fees netted against general and administrative expenses were approximately $0.1 million and $0.3 million, respectively.

(p) 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 Company s 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. At March 31, 2007, deferred tax liabilities of approximately $0.7 million are recorded on the condensed consolidated balance sheets and deferred tax assets of $2.5 million, net of a valuation allowance of $1.9 million are also recorded. At December 31, 2006, deferred tax liabilities of approximately $0.7 million are recorded on the condensed consolidated balance sheets and deferred tax assets of $6.3 million, net of a valuation allowance of $2.3 million are also recorded.

The Company adopted Financial Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48) on January 1, 2007. FIN 48 requires that the Company recognize only the impact of income tax positions that, based on their merits, are more likely than not to be sustained upon audit by a taxing authority. It also requires expanded financial statement disclosure of such positions.

In evaluating its current tax positions in order to identify any material uncertain tax positions, the Company developed a policy in identifying uncertain tax positions that considers support for each tax position, industry standards, tax return disclosures and schedules and the significance of each position.

As of January 1, 2007, the date of adoption of FIN 48, the Company had no material uncertain tax positions. The Company does not currently anticipate that any significant uncertain tax positions will be recorded during the next 12 months.

(q) Revenue Recognition

Sales of oil, gas and NGL are recognized when produced quantities have 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, gas and NGL are 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 produced commodity and prevailing supply and demand conditions, so that the price of the oil, gas and NGL fluctuate to remain competitive with other available 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 March 31, 2007 or December 31, 2006.

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 condensed consolidated statements of operations for the three months ended March 31, 2007 and 2006.

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 revenues on the condensed consolidated statements of operations.

(r) Production Taxes

Oil, gas and NGL revenues are presented on a gross basis on the condensed consolidated statements of operations. Production taxes are included in operating expenses on the condensed consolidated statements of operations and were approximately $1.5 million and $0.9 million for the three months ended March 31, 2007 and 2006, respectively.

(3) Acquisitions and Dispositions

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 Stallion Energy LLC, acting as general partner for Cavallo Energy, LP, for a contract price of $415.0 million, subject to customary closing adjustments. The Texas Panhandle acquisition was financed with a combination of a private placement of our units (see Note 4) and borrowings under the Company s senior secured revolving credit facility.

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

	Texas Panhandle	
	(in thousands)	
Cash	$	407,762
Estimated transaction costs	3,006	
Estimated closing adjustments	3,508	
	414,276	
Fair value of liabilities assumed	1,706	
Total purchase price	$	415,982

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

	Texas Panhandle	
	(in thousands)	
Oil and gas properties	$	415,244
Vehicles and buildings	738	
	$	415,982

The preliminary purchase price allocation is 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 oil and gas properties. To estimate the fair values of these properties, we prepared estimates of oil, gas and NGL 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. There were no unproved properties identified with the Texas Panhandle acquisition. As noted, the purchase price allocation is preliminary; it is subject to final closing adjustments and will be finalized within one year of the acquisition date.

The following unaudited pro forma financial information presents a summary of Linn s consolidated results of operations for the three months ended March 31, 2007 and 2006, assuming the acquisition of our Texas Panhandle properties had been completed as of January 1, 2006, including adjustments to reflect the allocation of the purchase price to the acquired net assets. The pro forma financial information also assumes the Company s February 2007 private placement of units (see Note 4) was completed on January 1, 2006, since the private placement was contingent on the Texas Panhandle acquisition. In addition, the pro forma financial information assumes that our California acquisitions of certain affiliated entities of Blacksand Energy, LLC and certain Mid-Continent assets of the Kaiser-Francis Oil Company were completed as of January 1, 2006. The California and Mid-Continent acquisitions were completed in 2006 and the revenues and expenses are included in the consolidated results of the Company effective August 1, 2006 and September 1, 2006, respectively. The revenues and expenses of the Texas Panhandle assets are included in the consolidated results of the Company effective February 1, 2007. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of these dates.

	Three Months Ended March 31,				
	2007			**2006**	
Total revenues	$	(13,348	)	$	97,691
Total operating expenses	$	39,004		$	31,417
Net income (loss)	$	(66,777	)	$	53,678
Net income (loss) per unit:					
Units basic	$	(1.33	)	$	1.33
Units diluted	$	(1.33	)	$	1.33
Class C units basic	$	(1.33	)	$	1.33
Class C units diluted	$	(1.33	)	$	1.33

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

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 closing adjustments. In connection with these acquisitions and the Texas Panhandle acquisition, the Company amended its credit facility to increase the borrowing base from $480.0 million to $725.0 million (see Note 7).

In February 2007, the Company paid, to a third-party, fees of $10.0 million and a term net-profits interest in conjunction with the Company s purchase of a net profits interest in certain oil and gas properties in California from Aera Energy LLC. The $10.0 million is recorded in oil and gas properties on the Company s condensed consolidated balance sheets and is depleted based on units of production. Effective April 1, 2007, the Company assumed operatorship of the properties and began distributing revenue based on formulas set forth in the respective agreements.

In March 2007, the Company sold certain of its oil and gas properties located in New York for cash of approximately $2.5 million and recorded a gain of approximately $0.9 million. The gain is included in other revenues on the condensed consolidated statements of operations.

(4) Unitholders Capital

Private Placements

In February 2007, the Company entered into 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). Proceeds, net of expenses, were $353.1 million. The proceeds from the Class C Private Placement were used to finance the Texas Panhandle acquisition and the acquisitions of certain gas properties in West Virginia (see Note 3).

In April 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of the Class C units into units. 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.

In connection with its October 2006 private placement of Class B units, the Company also agreed to file a registration statement with the SEC covering the units and the units underlying the Class B units and that the registration statement would be declared effective by the SEC no later than 165 days following the Class B private placement closing. The effective date deadline was extended under a separate agreement to 210 days.

The Company could be required to pay purchasers, as liquidated damages, certain amounts as defined in the agreements in the event the registration effectiveness deadlines are not met. The potential payments would be approximately $0.8 million and $0.9 million for the October 2006 and February 2007 placements, respectively, for each 30 day period that the registration deadlines are not met, up through 90 days. Subsequent to 90 days, the potential payments would increase for each 30 day period, up to a maximum of 1.0% of the gross proceeds of each offering. If an accounting change resulted in units being reclassified as a liability, any payment would be further limited to the units remaining under equity treatment on the financial statements of the Company.

The Company evaluated its liability exposure related to the liquidated damages and determined its probable payments to be approximately $0.3 million. As such, the Company recorded a liability for this amount on its condensed consolidated balance sheets at March 31, 2007. Subsequent changes in the amount of the liability will be recorded in other income and (expenses) on the condensed consolidated statements of operations. The Company will continue to monitor and assess its exposure in this matter; however, the Company does not currently expect payments under these agreements, if any, to be material to the Company s financial position or results of operations.

Cancellation of Units

In January 2007, the Company purchased 226,561 restricted units from an employee for $7.4 million (market price on the day of purchase) in conjunction with the vesting of restricted unit awards. The proceeds were used to fund the employee s payroll taxes on the award and the Company cancelled the units.

Initial Public Offering

In the first quarter of 2006, the Company completed its initial public offering (IPO) of 12,450,000 units representing limited liability interests 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, $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.

(5) 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:

	March 31, 2007 (in thousands)	December 31, 2006
Unproved properties	$ 8,438	$ 8,624
Proved properties:		
Leasehold, equipment and drilling	1,164,226	737,202
Gas compression plant and pipelines	80,699	20,812
Less accumulated depletion, depreciation and amortization	1,253,363	766,638
	(44,188)	(33,349)
Net capitalized costs	$ 1,209,175	$ 733,289

(6) Property and Equipment

Property and equipment consists of the following:

	March 31, 2007 (in thousands)	December 31, 2006
Land	$ 320	$ 308
Buildings and leasehold improvements	3,190	2,759
Vehicles	4,144	3,097
Aircraft	5,890	5,890
Drilling equipment	10,773	8,611
Furniture and equipment	2,333	1,966
	26,650	22,631
Less accumulated depreciation	(2,583)	(1,877)
	$ 24,067	$ 20,754

Depreciation expense for the three months ended March 31, 2007 and 2006, was approximately $0.7 and $0.2 million, respectively.

(7) Credit Facility

At March 31, 2007, the Company had an $800.0 million senior secured revolving credit facility with a maturity of August 2010, and a borrowing base of $725.0 million (Credit Facility). In February 2007, in conjunction with the Texas Panhandle acquisition and two acquisitions in West Virginia (see Note 3), the Company amended its Credit Facility, increasing the borrowing base from $480.0 million to $725.0 million. In connection with this amendment, in the first quarter of 2007, the Company paid fees of approximately $1.6 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. 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 certain financial ratios. The Company is in compliance with all financial and other covenants of its Credit Facility.

As of March 31, 2007 and December 31, 2006, the Credit Facility consisted of the following:

	March 31, 2007	**December 31, 2006**
	(in thousands)	
Total (1)	$ 596,750	$ 425,750
Less current maturities		
	$ 596,750	$ 425,750

(1) Variable rate of 6.875% and 7.125% at March 31, 2007 and December 31, 2006, respectively.

At March 31, 2007, the Company also had $5.0 million outstanding letters of credit, which reduce its borrowing availability under the Credit Facility. At March 31, 2007, available borrowing under the Credit Facility was $123.2 million.

Total accrued interest on the Credit Facility was approximately $2.4 million and $2.1 million at March 31, 2007 and December 31, 2006, respectively.

(8) Long-term Notes Payable

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

	March 31, 2007	December 31, 2006
	(in thousands)	
Note payable to a bank with an interest rate of 6.14%, payable in monthly installments of approximately $3, including interest, through September 2024. The note is secured by an office building.	$ 369	$ 372
Various notes for the purchase of vehicles and equipment, payable in monthly installments totaling approximately $88 and $88, as of March 31, 2007 and December 31, 2006, respectively, including interest. The interest rates range from 3.9%-9.11%. The notes are secured by the vehicles and equipment purchased and expire at various dates from 2007 through 2011. (1)	2,752	2,989
	3,121	3,361
Less current maturities	(871)	(874)
	$ 2,250	$ 2,487

(1) At March 31, 2007 and December 31, 2006, includes approximately $16 and $1.0 million, respectively, of notes payable on which interest was imputed at 7.0%.

As of March 31, 2007, maturities on the aforementioned long-term notes payable were as follows:

	(in thousands)
2007	$ 634
2008	870
2009	641
2010	446
2011	229
Thereafter	301
	$ 3,121

(9) 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 generally does not require collateral.

A majority of the Company s largest customers are oil and gas producers, suppliers and operators. For the three months ended March 31, 2007, the Company s three largest customers represented approximately 34%, 19% and 12%, respectively, of the Company s sales. The Company s two largest customers represented approximately 70% and 10%, of the Company s sales for the three months ended March 31, 2006, respectively.

At March 31, 2007, three customers trade accounts receivable from oil, gas and NGL sales accounted for more than 10% of the Company s total trade accounts receivable. At March 31, 2007, trade accounts receivable from these customers represented approximately 38%, 17% and 16% of the Company s receivables. 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.

(10) Commitments and Contingencies

The Company would be exposed to oil, gas and NGL price fluctuations on underlying sale contracts should the counterparties to the Company s derivative instruments or the counterparties to the Company s oil, gas and NGL marketing contracts not perform. Such non-performance is not anticipated. There were no counterparty default losses during the three months ended March 31, 2007 or 2006.

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.

(11) 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, gas and NGL. The Company enters into derivative instruments such as swap contracts and put options to hedge a portion of its forecasted oil, gas and NGL sales.

Settled derivatives on gas production for the three months ended March 31, 2007, included a volume of 4,695 MMBtu at an average contract price of $8.42. Settled derivatives on oil and NGL production for the three months ended March 31, 2007 included a volume of 392 MBbls at an average contract price of $69.73. The gas derivatives are settled based upon the closing NYMEX future price of gas on the settlement date, which occurs on the third day preceding the production month. The oil transactions are settled based upon the average month s 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 March 31, 2007 and represents, as of such date, our derivatives in place through December 31, 2011, on annual production volumes:

	Year 2007	Year 2008	Year 2009	Year 2010	Year 2011
Gas Positions					
Fixed Price Swaps:					
Hedged Volume (MMBtu)	5,908	10,264	10,405	8,520	7,800
Average Price ($/MMBtu)	$ 8.74	$ 8.37	$ 7.73	$ 7.20	$ 7.20
Puts:					
Hedged Volume (MMBtu)	6,446	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)	12,354	17,317	17,365	15,480	14,760
Average Price ($/MMBtu)	$ 8.45	$ 8.25	$ 7.64	$ 7.34	$ 7.34

	Year 2007	Year 2008	Year 2009	Year 2010	Year 2011
Oil Positions					
Fixed Price Swaps:					
Hedged Volume (MMBbls)	375	560	580	550	525
Average Price ($/Bbl)	$ 75.83	$ 74.31	$ 73.87	$ 74.54	$ 61.58
Puts:					
Hedged Volume (MMBbls)	1,125	1,550	1,550	1,700	1,750
Average Price ($/Bbl)	$ 66.33	$ 66.29	$ 66.29	$ 66.18	$ 65.00
Total:					
Hedged Volume (MMBbls)	1,500	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.

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

	March 31, 2007	December 31, 2006
Outstanding notional amounts of gas hedges (MMBtu)	77,276	31,503
Maximum number of months gas hedges outstanding	57	35
Outstanding notional amounts of oil hedges (MBbls)	10,265	8,700
Maximum number of months oil hedges outstanding	58	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.

(12) Earnings Per Unit

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit is computed by adjusting the average number of units outstanding for the dilutive effect, if any, of unit equivalents. The Company uses the treasury stock method to determine the dilutive effect. At March 31, 2007, 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 C units. See Note 4 for details regarding the Class C 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 condensed consolidated statements of operations for each class of units issued and outstanding at March 31, 2007, units and Class C units. Net income per unit is allocated to the units and the Class C units on an equal basis. Since the Class C units were converted to units in April 2007, they share equally in the May 2007 distributions and all future distributions. The Company made no distributions to Class C unitholders during the period the Class C units were outstanding.

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

	Three Months Ended March 31,					
	2007			**2006**		
	(in thousands, except per unit amounts)					
Net income (loss)	$	(67,847	)	$	21,977	
Weighted average units outstanding:						
Basic units outstanding	45,456			26,273		
Dilutive effect of unit equivalents and Class C units (1)						
Diluted units outstanding	45,456			26,273		
Weighted average Class C units outstanding:						
Basic Class C units outstanding	4,894					
Dilutive effect of unit equivalents						
Diluted Class C units outstanding	4,894					
Net income (loss) per unit:						
Units basic	$	(1.35	)	$	0.84	
Units diluted	$	(1.35	)	$	0.84	
Class C units basic	$	(1.35	)	$		
Class C units diluted	$	(1.35	)	$		

(1) Excludes the effect of average anti-dilutive common stock equivalents related to out-of-the-money unit options, restricted units and unit warrants of 451,252 and 188,257 for the three months ended March 31, 2007 and 2006, respectively. In addition, excludes the effect of average anti-dilutive Class C units for the three months ended March 31, 2007. All equivalent units are anti-dilutive for the three months ended March 31, 2007 as the Company reported a net loss from operations.

(13) Unit-Based Compensation

Employee Grants

During the three months ended March 31, 2007, 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 with an aggregate fair value of approximately $13.0 million and $1.7 million, respectively. In addition, during the three months ended March 31, 2007, the Company granted 50,000 unit options to a new officer of the Company with a fair value of approximately $0.3 million. These restricted units and options vest ratably over three years.

For the three months ended March 31, 2007 and 2006, the Company recorded unit-based compensation expense of approximately $3.3 million and $5.7 million, respectively, as a charge against income before income taxes and it is included in general and administrative expenses on the condensed consolidated statements of operations.

Subsequent to March 31, 2007, the Company issued 30,000 restricted units and 30,000 unit options to a new officer of the Company.

Non-Employee Grants

In February 2007, the Company granted an aggregate 150,000 unit warrants to certain individuals in connection with a transition services agreement entered into with the Texas Panhandle acquisition (see Note 3). The unit warrants have an exercise price of $25.50 per unit warrant, may be exercised in whole or in-part on or after December 13, 2007, and expire ten years from issuance. In accordance with SFAS 123R, the Company computed the fair value of the unit warrants using the Black-Scholes model. At March 31, 2007, the aggregate fair value of the unit warrants was approximately $1.2 million and the expense will be recognized over the five month term of the agreement, or through June 30, 2007. For the three months ended March 31, 2007, the Company recorded approximately $0.5 million as a charge against income before income taxes and it is included in general and administrative expenses on the condensed consolidated statements of operations. In accordance with Emerging Issues Task Force Issue No. 96-18 *Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction With Selling, Goods or Services,* the fair value of the warrants was recomputed at March 31, 2007, and will be recomputed on June 30, 2007.

(14) Related Party Transactions

During the three months ended March 31, 2006, the Company made payments of approximately $61,000 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 expenses on the condensed consolidated statements 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 ended. Simultaneous with this transaction, the senior executive was able to fully liquidate the investment in the aircraft owned by his company.

(15) Subsequent Event

In May 2007, the Company entered into a definitive purchase agreement to acquire certain oil and gas properties in the Texas Panhandle for $90.5 million, subject to customary closing adjustments. The Company anticipates the acquisition will close on or before June 30, 2007 and will be financed with borrowings under the Company s existing Credit Facility.

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

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 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. Our properties and our oil and gas reserves are currently located in four core areas:

- Appalachian Basin, which includes West Virginia, Pennsylvania 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.

From inception through March 31, 2007, we have completed 17 acquisitions of oil and gas properties and related gathering and pipeline assets for an aggregate purchase price of approximately $1.1 billion, with total proved reserves of approximately 772.0 Bcfe, or an acquisition cost of approximately $1.44 per Mcfe.

In February 2007, the Company completed the acquisition of certain oil and gas properties and related assets in the Texas Panhandle for a contract price of $415.0 million, subject to customary closing adjustments (see Note 3 in Notes to Condensed 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 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.

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.

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. Developmental drilling costs are capitalized and costs for exploratory wells are 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.

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 on March 30, 2007, which will reduce reliance on contract rigs. 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, gas or NGL 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 managing 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, gas and NGL prices and levels of production. As of March 31, 2007, 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, pipeline capacity and favorable weather conditions. 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, gas and NGL 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, gas and NGL prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil, gas or NGL could materially and adversely affect our financial position, our results of operations, the quantities of productive 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.

Results of Operations - Three Months Ended March 31, 2007 Compared to Three Months Ended March 31, 2006

	Three Months Ended March 31, 2007 (in thousands)	2006	Variance
Revenues:			
Gas sales	$ 23,360	$ 16,007	$ 7,353
Oil sales	9,758	368	9,390
Natural gas liquid sales	6,086		6,086
Total oil, gas and natural gas liquid sales	39,204	16,375	22,829
Gain (loss) on oil and gas derivatives	(60,441)	24,246	(84,687)
Natural gas marketing revenues	1,778	1,218	560
Other revenues	2,090	289	1,801
Total revenues	$ (17,369)	$ 42,128	$ (59,497)
Expenses:			
Operating expenses	$ 12,456	$ 2,994	$ 9,462
Natural gas marketing expenses	1,347	983	364
General and administrative expenses	10,621	9,470	1,151
Depreciation, depletion and amortization	11,851	3,700	8,151
Total expenses	$ 36,275	$ 17,147	$ 19,128
Other income and (expenses):			
Interest expense, net of amounts capitalized	$ (9,913)	$ (2,639)	$ (7,274)

	Three Months Ended March 31, 2007	2006	Percentage Increase (Decrease)
Production:			
Gas production (MMcf)	3,374	1,798	87.7 %
Oil production (MBbls)	215	6	3,483.3 %
Natural gas liquid production (MBbls)	127		
Total production (MMcfe)	5,424	1,836	195.4 %
Average daily production (Mcfe/d)	60,267	20,400	195.4 %
Weighted average realized prices: (1)			
Gas (Mcf)	$ 8.40	$ 9.74	(13.8)%
Oil (Bbl) (2)	$ 64.47	$ 58.46	10.3 %
Natural gas liquid (Bbl)	$ 47.92	$	
Total (Mcfe)	$ 8.90	$ 9.72	(8.4)%
Average unit costs per Mcfe of production (non-GAAP):			
Operating expenses	$ 2.30	$ 1.63	41.1 %
General and administrative expenses (3)	$ 1.27	$ 0.97	30.9 %
Depreciation, depletion and amortization	$ 2.18	$ 2.02	7.9 %

(1) Includes the effect of realized gains of $9.1 million and $3.3 million on oil and gas derivatives for the three months ended March 31, 2007 and 2006, respectively.

(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 NGL being mixed into the oil stream, prices realized average approximately 82% of NYMEX.

(3) 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 three months ended March 31, 2007 and 2006 excludes approximately $3.7 million and $5.7 million, respectively, of unit-based compensation expense and unit warrant expense. The measure for the three months ended March 31, 2006 excludes approximately $2.0 million of bonuses paid to certain executive

officers in connection with our initial public offering. General and administrative expenses including these amounts was $1.96 per Mcfe and $5.16 per Mcfe for the three months ended March 31, 2007 and 2006, respectively.

Revenue

Gas, oil and NGL sales increased to approximately $39.2 million for the three months ended March 31, 2007, from $16.4 million for the three months ended March 31, 2006.

The increase in revenue from gas, oil and NGL sales was primarily attributable to increased production. Total production increased to 5,424 MMcfe during the three months ended March 31, 2007, from 1,836 MMcfe during the three months ended March 31, 2006. Gas production increased to 3,374 MMcf during the three months ended March 31, 2007, from 1,798 MMcf during the three months ended March 31, 2006. 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 2007 and 2006. The Company drilled 41 wells during the three months ended March 31, 2007, compared to 29 wells during the three months ended March 31, 2006. Oil production increased to 215 MBbls during the three months ended March 31, 2007, from 6 MBbls during the during the three months ended March 31, 2006, due to the California and Texas Panhandle acquisitions in August 2006 and February 2007, respectively. The acquisition in the Texas Panhandle also increased NGL production to 127 MBbls during the three months ended March 31, 2007, from zero during the comparative period of the prior year.

Hedging Activities

During the three months ended March 31, 2007, we entered into commodity pricing derivative contracts for approximately 115% of our gas production and 110% of our oil production, which resulted in revenues that were $9.1 million greater than we would have achieved at unhedged prices. The calculation of percentage production hedged for the three months ended March 31, 2007 includes an adjustment to reflect the production attributable to the Texas Panhandle acquisition, which was hedged, but was not included in the Company s reported production; instead, it was reflected as a purchase price adjustment (see Note 3 in Notes to Condensed Consolidated Financial Statements). During the three months ended March 31, 2006, we entered into commodity pricing derivative contracts for approximately 100% of our oil and gas production, which resulted in revenues that were $3.3 million greater than we would have achieved at unhedged prices. Unrealized losses on derivatives in the amount of $69.5 million for the three months ended March 31, 2007 and unrealized gains of $21.0 million for the three months ended March 31, 2006, were also recorded. Unrealized gains and losses result from changes in market valuations of oil and gas derivatives as future oil and gas price expectations change compared to the contract price on the derivative. During the quarter, short-term oil and gas prices increased, which reduced the market value of the derivatives. Such market value adjustment, if realized in the future, would be offset by higher actual oil and gas prices for our production.

Expenses

Operating expenses include lease operating expenses, labor, field office expenses, 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 $12.5 million for the three months ended March 31, 2007, from $3.0 million for the three months ended March 31, 2006, due to the increase in the number of producing wells as a result of the acquisitions completed in both the first quarter of 2007 and in 2006 and the drilling of 41 wells in the three months ended March 31, 2007, and 400 wells from inception through March 31, 2007.

In addition, our average operating expenses per equivalent unit of production increased to $2.30 for the three months ended March 31, 2007, compared to $1.63 for the three months ended March 31, 2006, due to the changing mix of production from third quarter 2006 to include oil and NGL production which has higher operating costs than our gas wells. Finally, we have incurred costs in 2007 for workover and maintenance of our wells to enhance future production and/or offset decline.

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 approximately $10.6 million for the three months ended March 31, 2007, from $9.5

million for the three months ended March 31, 2006. The increase in general and administrative expenses was primarily due to approximately $3.6 million of costs incurred to support our rapid growth through acquisitions and position the Company for future growth, which include increasing our staffing levels to manage the 400 wells drilled and 4,246 wells acquired from inception in 2003 through March 31, 2007, relocating the Company headquarters from Pittsburgh, Pennsylvania to Houston, Texas, recruiting key management team members and performing the functions associated with being a public company. The latter costs include preparation of public partnership tax reporting, audit fees, proxy and printing costs and other professional fees. In addition, acquisition costs that are not eligible for capitalization, including internal and indirect costs for completed acquisitions, as well as direct costs associated with acquisition efforts that have not reached fruition, contributed to the increase. The Company also incurred unit warrant expense of approximately $0.5 million in connection with the issuance of unit warrants pursuant to a transition services agreement associated with the Texas Panhandle properties (see Note 13 in Notes to Condensed Consolidated Financial Statements). The increase in general and administrative expenses was partially offset by decreased employee unit-based compensation expense, which was $3.3 million during the three months ended March 31, 2007, compared to $5.7 million during the comparative quarter of 2006. General and administrative expenses are presented net of approximately $0.1 million and $0.3 million during the three months ended March 31, 2007 and 2006, respectively, which represent expense reimbursements from other working interest owners.

Depreciation, depletion and amortization increased to approximately $11.9 million for the three months ended March 31, 2007, from $3.7 million for the three months ended March 31, 2006. Of this increase, approximately $4.7 million was as a result of depletion related to the California and Mid-Continent acquisitions in the third quarter of 2006 and the Texas Panhandle acquisition in the first quarter of 2007. 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 primarily attributable to decreases in gas prices. During the three months ended March 31, 2007 and 2006, the Company capitalized approximately $1.9 million and $0.3 million, respectively, of costs 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 in the three months ended March 31, 2007 due to the Company s purchase and placement of two drilling rigs into service during the third quarter of 2006 and one additional drilling rig in the first quarter of 2007. Company personnel also perform activities using leased equipment, and did so prior to the purchase of its own rigs.

Interest and financing income (expense) increased to a net expense of $9.9 million for the three months ended March 31, 2007, compared to a net expense of $2.6 million for the three months ended March 31, 2006, primarily due to increased debt levels associated with acquisitions and drilling. Cash payments for interest increased to $9.3 million for the three months ended March 31, 2007, compared to $3.3 million for the three months ended March 31, 2006. 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 $0.2 million and $0.4 million for the three months ended March 31, 2007 and 2006, respectively. These amounts are non-cash gains.

Income tax was an expense of approximately $3.7 million for the three months ended March 31, 2007 compared to an expense of approximately $0.1 million for the three months ended March 31, 2006. The Company s taxable subsidiaries generated net operating losses for the year ended December 31, 2006. Management has subsequently recovered expenses through an intercompany charge for services from Linn Operating, Inc. to Linn Energy, LLC, which resulted in a corresponding tax expense in first quarter of 2007.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires management to select and apply accounting policies that best provide the framework to report its results of operations and financial position. The selection and application of those policies requires management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of March 31, 2007, there have been no significant changes with regard to the critical accounting policies disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2006. The policies disclosed included the accounting for oil and gas properties, oil and gas reserve quantities, revenue recognition, purchase accounting and derivative instruments.

Liquidity and Capital Resources

We have utilized public and private equity 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 March 31, 2007, we had cash and cash equivalents of approximately $1.0 million compared to $6.6 million at December 31, 2006.

Cash used by operating activities for the three months ended March 31, 2007 was $37.9 million, compared to cash provided by operating activities of $5.4 million for the three months ended March 31, 2006. The decrease in cash provided by operating activities was primarily due to premiums paid for oil and gas derivatives of $53.0 million, since the reported net loss arose predominately from the non-cash market valuation adjustment at March 31, 2007 for outstanding hedge investments. Cash provided by operations for the three months ended March 31, 2006, resulted primarily from net income from operations. See Results of Operations above for details about the increase in components of net income.

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of oil, gas and NGL prices. Oil, gas and NGL 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 received for our production. We enter into derivative arrangements to reduce the impact of oil and gas price volatility on our operations. Currently, we use fixed price swaps and puts to reduce our exposure to the volatility in oil, gas and NGL prices. See Note 11 in Notes to Condensed Consolidated Financial Statements for details about our derivatives in place through December 31, 2011.

Statements of Cash Flows Investing Activities

Cash used in investing activities was $459.9 million for the three months ended March 31, 2007, compared to $19.5 million for the three months ended March 31, 2006. The increase in cash used in investing activities was primarily due to an increase in acquisition activity during the three months ended March 31, 2007, compared to the prior year.

The total cash used in investing activities for the three months ended March 31, 2007 includes $387.7 million for the Texas Panhandle acquisition and $38.5 million the acquisitions of certain gas properties in West Virginia. See Note 3 in Notes to Condensed Consolidated Financial Statements for additional details. Other acquisitions, including acquisitions of additional working interests in our current wells, were approximately $14.2 million and property, plant and equipment purchases accounted for $3.3 million. The total for the three months ended March 31, 2007 also includes $10.4 million for the drilling and development of oil and gas properties.

Statements of Cash Flows Financing Activities

Cash provided by financing activities was $492.2 million for the three months ended March 31, 2007, compared to $18.9 million for the three months ended March 31, 2006.

The Company recorded gross proceeds of $360.0 million from a private placement of its units during the three months ended March 31, 2007 (see Private Placement Class C Units below). The proceeds, net of expenses of approximately $6.9 million, were used to finance the Texas Panhandle acquisition and the acquisitions of certain gas properties in West Virginia. Total proceeds from borrowings under the Credit Facility during the three months ended March 31, 2007 were $171.0 million.

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 $22.7 million was paid in February 2007.

In April 2007, the Company s Board of Directors declared a distribution of $0.52 per unit with respect to the first quarter of 2007. The distribution totaling approximately $30.1 million will be paid in May 2007 to unitholders of record at the close of business on May 3, 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 Placements

In February 2007, the Company entered into 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 Texas Panhandle acquisition and the acquisitions of certain gas properties in West Virginia. See Note 3 in Notes to Condensed Consolidated Financial Statements.

In April 2007, at a special meeting of Linn unitholders, unitholders approved the one-for-one conversion of the Class C units into units. 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.

In connection with its October 2006 private placement of Class B units, the Company also agreed to file a registration statement with the SEC covering the units and the units underlying the Class B units and that the registration statement would be declared effective by the SEC no later than 165 days following the Class B private placement closing. The effective date deadline was extended under a separate agreement to 210 days.

The Company could be required to pay purchasers, as liquidated damages, certain amounts as defined in the agreements in the event the registration effectiveness deadlines are not met. The potential payments would be approximately $0.8 million and $0.9 million for the October 2006 and February 2007 placements, respectively, for each 30 day period that the registration deadlines are not met, up through 90 days. Subsequent to 90 days, the potential payments would increase for each 30 day period, up to a maximum of 1.0% of the gross proceeds of each offering. If an accounting change resulted in units being reclassified as a liability, any payment would be further limited to the units remaining under equity treatment on the financial statements of the Company.

The Company evaluated its exposure to the payment of liquidated damages under these agreements and determined its probable payments to be approximately $0.3 million. As such, the Company recorded a liability for this amount on its condensed consolidated balance sheets at March 31, 2007. Subsequent changes in the amount of the liability will be recorded in other income and (expenses) on the condensed consolidated statements of operations. The Company will continue to monitor and assess its exposure in this matter; however, the Company does not currently expect payments under these agreements, if any, to be material to the Company s financial position or results of operations.

Initial Public Offering

In the first quarter of 2006, the Company completed its initial public offering (IPO) of 12,450,000 units representing limited liability interests 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, $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.

Credit Facility

At March 31, 2007 the Company had an $800.0 million senior secured revolving credit facility with a maturity of August 2010, and a borrowing base of $725.0 million. In February 2007, in conjunction with the Texas Panhandle acquisition and two acquisitions in West Virginia (see Note 3 in Notes to Condensed Consolidated Financial Statements) the Company amended its Credit Facility, increasing the borrowing base from $480.0 million to $725.0 million. In connection with this amendment, in the first quarter of 2007, the Company paid fees of approximately $1.6 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 April 30, 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 prepared by reserve engineers taking into account the oil, gas and NGL 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.

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 certain financial ratios. The Company is in compliance with all financial and other covenants of its Credit Facility.

Off-Balance Sheet Arrangements

At March 31, 2007, 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

The Company regularly analyzes current information and accrues for probable liabilities on the disposition of certain matters, as necessary. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Commitments and Contractual Obligations

The Company has contractual obligations for long-term debt, operating leases and other long-term liabilities that were summarized in a table of contractual obligations in the 2006 Annual Report on Form 10-K. As of March 31, 2007, there have been no significant changes to the Company s contractual obligations from December 31, 2006.

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 and other;
- (Gain) loss on sale of assets;
- Accretion of asset retirement obligation;
- Unrealized (gain) loss on oil and gas derivatives;
- Unit-based compensation and unit warrant expense;
- IPO cash bonuses; and
- Income tax provision.

Adjusted EBITDA is a significant performance metric used by our 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:

	Three Months Ended March 31,	
	2007	**2006**
	(in thousands)	
Net income (loss)	$ (67,847)	$ 21,977
Plus:		
Interest expense, net of amounts capitalized	9,913	2,639
Depreciation, depletion and amortization	11,851	3,700
Write-off of deferred financing fees and other	804	374
(Gain) loss on sale of assets	(945)	18
Accretion of asset retirement obligation	110	58
Unrealized (gain) loss on oil and gas derivatives	69,514	(20,923)
Unit-based compensation and unit warrant expense	3,740	5,680
IPO cash bonuses		2,039
Income tax provision (1)	3,632	119

Adjusted EBITDA		$	30,772		$	15,681	

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

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As noted above, Adjusted EBITDA is non-GAAP performance measure used by our management and is a quantitative measure used in the oil and gas industry. On our condensed consolidated statements of cash flows, our net cash used by operating activities for the three months ended March 31, 2007, was approximately $37.9 million and includes approximately $54.1 million unrealized loss on oil and gas and interest rate derivatives and $3.7 million unit-based compensation and unit warrant expense. Our net cash used by operating activities for the three months ended March 31, 2006, was approximately $5.4 million and includes $24.0 million gain on unrealized oil and gas derivatives and $5.7 million unit-based compensation expense.

New Accounting Standards

There have been no accounting standards that materially affected the Company this period; however, see Note 2 in Notes to Condensed Consolidated Financial Statements for detail regarding FIN 48.

Cautionary Statement

This Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q, are forward looking statements. These forward-looking statements may be found in Item 2. In some cases, forward-looking statements can be identified by terminology such as may, will, could, should, expect, plan, project, intend, anticipate, believe, estimate, predict, poten continue, the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Quarterly Report on Form 10-Q 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 Quarterly Report on Form 10-Q 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 Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006, and elsewhere in our Annual Report and also in this Quarterly Report on Form 10-Q. 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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about 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, gas and NGL production. Realized pricing is primarily driven by the spot market prices applicable to our 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, gas and NGL price fluctuations. We do not hold or issue derivative instruments for speculative trading purposes.

At March 31, 2007, the fair value of hedges that settle during the next twelve months was an asset of approximately $24.5 million and a liability of approximately $5.9 million for a total asset of approximately $18.6 million, for which we are owed by the counterparty. A 10% increase in the index oil and gas prices above the March 31, 2007 prices for the next twelve months would result in a reduction in the value of our hedges of approximately $16.4 million; conversely, a 10% decrease in the index oil and gas prices would result in an increase of approximately $19.8 million.

Our derivatives as of March 31, 2007, for 2007 through 2011, are summarized in the table presented in Note 11 in Notes to Condensed Consolidated Financial Statements.

Interest Rate Risk

At March 31, 2007, we had long-term debt outstanding of $596.8 million under our Credit Facility, which incurred interest at floating rates in accordance the Credit Facility agreement. As of March 31, 2007, our rate based on the one-month LIBOR was approximately 6.875%. A 1% increase in the one-month LIBOR would result in an estimated $6.0 million increase in annual interest expense.

In order to finance the Texas Panhandle 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 7 in Notes to Condensed 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 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 March 31, 2007, 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 March 31, 2007 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 4. 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 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 March 31, 2007. 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 condensed consolidated financial statements included in this Quarterly Report on Form 10-Q 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 weaknesses in internal control. 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 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.

Remediation activities. During 2006, Company management took 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.

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 non-financial 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

During the three months ended March 31, 2007, we have not made any changes that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, as defined in Rule 13(a)-15(f) under the Exchange Act.

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.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

Not applicable.

Item 1A. Risk Factors

Our business has many risks. As of the date of this report, the factors that have materially changed from those reported in Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006 are presented below. These risk factors primarily relate to the addition of NGL to our revenue stream in the first quarter of 2007, in conjunction with our acquisition of properties in the Texas Panhandle. 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

If commodity prices decline significantly for a prolonged period, our cash flow from operations will decline, and we may have to lower our distribution or may not be able to pay distributions at all.

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

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

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

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

Declines in oil, gas and NGL prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our 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, gas and NGL reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The overall rate of decline for our production will change if production from our existing wells declines in a different manner than we have estimated and can change when we drill additional wells, make acquisitions and under other circumstances. Thus, our future oil, gas and NGL reserves and production and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and finding or acquiring additional economically recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our cash flow from operations and our ability to make distributions to our unitholders.

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

No one can measure underground accumulations of oil, gas and NGL in an exact way. Reserve engineering requires subjective estimates of underground accumulations of oil, gas and NGL and assumptions concerning future oil, gas and NGL prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Independent petroleum engineering firms prepare estimates of our proved reserves. 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, gas and NGL prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions by actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil, gas and NGL attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil, gas and NGL we ultimately recover being different from our reserve estimates.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated oil, gas and NGL reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs in effect on the day of estimate. However, actual future net cash flows from our properties also will be affected by factors such as:

- actual prices we receive for oil, gas and NGL;
- the amount and timing of actual production;
- supply of and demand for oil, gas and NGL; 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 our 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, gas and NGL reserves. These expenditures will reduce our cash available for distribution. We intend to finance our future capital expenditures with cash flow from operations and our financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;

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

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

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

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

We depend on certain key customers for sales of our oil, gas and NGL. To the extent these and other customers reduce the volumes of oil, gas and NGL they purchase from us, our revenues and cash available for distribution could decline.

For the three months ended March 31, 2007, Dominion Resources, Inc., ConocoPhillips and Duke Energy Corporation accounted for approximately 34%, 18% and 13%, respectively, of our total volumes, or 65% in the aggregate. For the year ended December 31, 2006, Dominion Resources, Inc. and ConocoPhillips accounted for approximately 53%, and 14%, respectively, of our total volumes, or 67% in the aggregate. To the extent these and other customers reduce the volumes of oil, gas or NGL that they purchase from us, our revenues and cash available for distribution could decline.

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, gas and NGL 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.

Item 2. **Unregistered Sales of Equity Securities and Use of Proceeds**

None not previously reported.

Item 3. **Defaults Upon Senior Securities**

None.

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

A special meeting of unitholders was held on January 18, 2007. The matters voted on at the meeting and the results were as follows:

1. To vote upon (a) a change in terms of our Class B units to provide that each Class B unit will convert automatically into one of our units and (b) the issuance of 9,185,968 units upon such conversion.

Votes For	Votes Against or Withheld	Abstentions
18,951,949	67,148	61,484

2. A proposal to approve an amendment to the Linn Energy, LLC Long-Term Incentive Plan (the LTIP) to provide that not more than 1,500,000 of the total number of units authorized to be issued under the LTIP may be issued as restricted units.

Votes For	Votes Against or Withheld	Abstentions
22,047,961	178,986	57,393

Item 5. **Other Information**

None.

Item 6. **Exhibits**

Exhibit Number	Description
2 .1	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 (incorporated herein by reference to Exhibit 3.3 to our Annual Report on Form 10-K filed on March 30, 2007)
3 .4	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated October 24, 2006 (incorporated herein by reference to Exhibit 3.3 to our Annual Report on Form 10-K filed on March 30, 2007)
3 .5	Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement of Linn Energy, LLC dated February 1, 2007 (incorporated herein by reference to Exhibit 3.3 to our Annual Report on Form 10-K filed on March 30, 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)
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 (incorporated herein by reference to Exhibit 3.3 to our Annual Report on Form 10-K filed on March 30, 2007)
10 .4*	Form of Executive Unit Option Agreement pursuant to the Linn Energy, LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 3.3 to our Annual Report on Form 10-K filed on March 30, 2007)
10 .5*	Form of Executive Restricted Unit Agreement pursuant to the Linn Energy, LLC Long-Term Incentive Plan (incorporated herein by reference to Exhibit 3.3 to our Annual Report on Form 10-K filed on March 30, 2007)
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)
10 .7	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 .8	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 .9	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 .10	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 .11	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 .12	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 .13	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)
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.

SIGNATURE

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

LINN ENERGY, LLC
(Registrant)

Date: May 14, 2007

/s/ Lisa D. Anderson
Lisa D. Anderson
Senior Vice President and Chief Accounting Officer
(As Duly Authorized Officer and Chief Accounting Officer)