LINN ENERGY, LLC
Form 10-Q
August 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 June 30, 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 (State or other jurisdiction of incorporation or organization)	**65-1177591** (IRS Employer Identification No.)
600 Travis, Suite 5100 **Houston, Texas** (Address of principal executive offices)	**77002** (Zip Code)

(281) 840-4000
(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 July 31, 2007, there were 65,629,506 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

	June 30, 2007 (Unaudited) (in thousands)	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 958	$ 6,595
Receivables trade, net	43,222	19,124
Inventory	599	578
Current portion of derivatives	29,402	37,817
Current portion of deferred tax assets, net		3,344
Other current assets	1,669	2,218
Total current assets	75,850	69,676
Oil and gas properties and related equipment (successful efforts method)	1,370,824	766,638
Less accumulated depreciation, depletion and amortization	(56,311)	(33,349)
	1,314,513	733,289
Property and equipment, net	27,152	20,754
Other assets:		
Long-term portion of derivatives	65,333	70,435
Deposit for oil and gas properties		20,086
Deferred financing fees and other assets, net	7,312	2,068
	72,645	92,589
Total assets	$ 1,490,160	$ 916,308

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

	June 30, 2007 (Unaudited) (in thousands, except unit amounts)	December 31, 2006
Liabilities and Unitholders Capital		
Current liabilities:		
Current portion of long-term notes payable	$ 999	$ 873
Accounts payable and accrued expenses	24,464	12,506
Current portion of derivatives	4,661	462
Revenue payable	4,832	1,839
Accrued interest payable	2,135	2,084
Gas purchases payable	329	253
Total current liabilities	37,420	18,017
Long-term liabilities:		
Notes payable	2,128	2,487
Credit facility	476,000	425,750
Asset retirement obligation	16,094	8,594
Derivatives	34,870	10,357
Other long-term liabilities	1,589	149
Total long-term liabilities	530,681	447,337
Total liabilities	568,101	465,354
Unitholders capital:		
65,605,765 units and 33,617,187 units issued and outstanding at June 30, 2007 and December 31, 2006, respectively	990,702	246,034
9,185,965 Class B units issued and outstanding at December 31, 2006		188,590
Accumulated income (loss)	(68,643)	16,330
	922,059	450,954
Total liabilities and unitholders capital	$ 1,490,160	$ 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 June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands, except per unit amounts)			
Revenues:				
Oil, gas and natural gas liquid sales	$ 49,217	$ 13,529	$ 88,421	$ 29,904
Gain (loss) on oil and gas derivatives	(17,707)	12,895	(78,148)	37,141
Natural gas marketing revenues	1,139	1,346	2,917	2,564
Other revenues	1,139	204	3,229	493
	33,788	27,974	16,419	70,102
Expenses:				
Operating expenses	14,714	2,933	27,170	5,927
Natural gas marketing expenses	879	1,189	2,226	2,172
General and administrative expenses	12,537	6,928	23,158	16,398
Depreciation, depletion and amortization	12,938	4,116	24,789	7,816
	41,068	15,166	77,343	32,313
	(7,280)	12,808	(60,924)	37,789
Other income and (expenses):				
Interest income	156	92	302	238
Interest expense, net of amounts capitalized	(9,952)	(2,696)	(19,865)	(5,335)
Other expenses	(20)	(158)	(824)	(550)
	(9,816)	(2,762)	(20,387)	(5,647)
Income (loss) before income taxes	(17,096)	10,046	(81,311)	32,142
Income tax benefit (provision)	(30)	193	(3,662)	74
Net income (loss)	$ (17,126)	$ 10,239	$ (84,973)	$ 32,216
Net income (loss) per unit:				
Units basic	$ (0.29)	$ 0.37	$ (1.62)	$ 1.19
Units diluted	$ (0.29)	$ 0.36	$ (1.62)	$ 1.18
Weighted average units outstanding:				
Units basic	59,293	27,830	52,413	27,056
Units diluted	59,293	28,094	52,413	27,325
Distributions declared per unit	$ 0.52	$ 0.32	$ 1.04	$ 0.32

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 June 30, 2007	2006	Six Months Ended June 30, 2007	2006
	(in thousands)			
Unitholders capital:				
Balance, beginning of period	$ 761,360	$ 146,065	$ 434,624	$ 16,024
Sale of units, net of expenses of $4,339				225,139
Sale of private placement units, net of expenses of $4,608 and $11,468	255,392		608,532	
Cancellation of member interests				(100,778)
Cancellation of units			(7,399)	
Distribution to members	(30,001)	(8,826)	(52,746)	(8,826)
Unit-based compensation expense	3,057	4,116	6,315	9,796
Unit warrant expense	894		1,376	
Balance, end of period	990,702	141,355	990,702	141,355
Accumulated income (loss):				
Balance, beginning of period	(51,517)	(40,878)	16,330	(62,855)
Net income (loss)	(17,126)	10,239	(84,973)	32,216
Balance, end of period	(68,643)	(30,639)	(68,643)	(30,639)
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	$ 922,059	$ 110,716	$ 922,059	$ 110,716

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

LINN ENERGY, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30, 2007	2006
	(in thousands)	
Cash flow from operating activities:		
Net income (loss)	$ (84,973)	$ 32,216
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	24,789	7,816
Amortization and write-off of deferred financing fees and other	904	812
Gain on sale of assets	(885)	
Accretion of asset retirement obligation	334	119
Unit-based compensation and unit warrant expense	7,691	9,796
Deferred income tax	3,360	(307)
Mark-to-market on derivatives:		
Total (gains) losses	77,951	(37,888)
Realized gains	13,504	5,592
Premiums paid for derivatives	(52,992)	(5,803)
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable	(21,654)	7,993
Decrease in inventory and other assets	528	3,809
Decrease in derivative receivables	3,766	
Increase (decrease) in accounts payable and accrued expenses	3,731	(5,791)
Increase in accrued interest payable	51	725
Increase (decrease) in revenue payable	2,993	(4,889)
Increase (decrease) in gas purchases payable	76	(331)
Increase in other liabilities	1,439	223
Net cash provided by (used in) operating activities	(19,387)	14,092
Cash flow from investing activities:		
Acquisition of oil and gas properties	(539,304)	(44,679)
Development of oil and gas properties	(43,478)	(19,429)
Purchases of property and equipment	(7,486)	(1,668)
Proceeds from sale of assets	2,934	25
Net cash used in investing activities	(587,334)	(65,751)
Cash flow from financing activities:		
Proceeds from sale of units	620,000	243,149
Redemption and cancellation of units	(7,399)	(114,449)
Principal payments on notes payable	(442)	(60,516)
Proceeds from credit facility	308,000	48,303
Payments on credit facility	(257,750)	(62,000)
Distribution to members	(52,746)	(8,826)
Offering costs	(6,917)	(844)
Financing fees	(1,662)	(564)
Net cash provided by financing activities	601,084	44,253
Net decrease in cash	(5,637)	(7,406)
Cash and cash equivalents:		
Beginning	6,595	11,041
Ending	$ 958	$ 3,635

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)

	Six Months Ended June 30, 2007 (in thousands)	2006
Supplemental disclosure of cash flow information:		
Cash payments for interest	$ 19,656	$ 4,957
Supplemental disclosures of non-cash investing and financing activities:		
Acquisitions of vehicles and equipment through issuance of notes payable	$ 237	$ 2,097
In connection with the purchase of oil and gas properties, liabilities were assumed as follows:		
Fair value of assets acquired	$ 545,789	$ 45,173
Cash paid	(539,304)	(44,679)
Liabilities assumed	$ 6,485	$ 494

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 and Significant Accounting Policies

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.

The condensed consolidated financial statements at June 30, 2007, and for the three and six months ended June 30, 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.

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.

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.

As of June 30, 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, reserve quantities, revenue recognition, purchase accounting and derivative instruments. Several of our more significant accounting policies are summarized below.

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

Derivative Instruments and Hedging Activities

The Company uses derivative financial instruments to achieve a more predictable cash flow from its oil, gas and NGL production by reducing its exposure to price fluctuations. As of June 30, 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. None of the Company s commodity or interest rate derivatives are designated as hedges under SFAS 133 and therefore the change in the fair value of the derivatives is included in the condensed consolidated statements of operations. See Note 9 and Note 10 for additional discussion related to derivative financial instruments.

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 awarded unit grants, unit options, restricted units, and phantom units to employees and non-employee directors. 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. See Note 12 for details regarding unit-based compensation granted during the six months ended June 30, 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.

Recently Issued Accounting Standards

In June 2007, the Financial Accounting Standards Board (FASB) ratified the consensus in Emerging Issues Task Force Issue 06-11 (EITF 06-11). EITF 06-11 is effective for fiscal years beginning after December 15, 2007 and requires, among other things, recognition as an increase to additional paid-in capital the realized income tax benefit from dividends or dividend equivalents that are paid to employees and charged to retained earnings. The Company is in the process of evaluating the impact of EITF 06-11 on its results of operations and financial position, but does not expect it will be material.

In April 2007, the FASB issued Staff Position No. 39-1, Amendment of FASB Interpretation No. 39 (FSP No. FIN 39-1). The terms conditional contracts and exchange contracts have been replaced with the more general term derivative contracts. In addition, FSP No. FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a Company s accounting policy with respect to offsetting fair value amounts. The guidance in FSP No. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. The Company does not believe that the adoption of FSP No. FIN 39-1 will have a material impact on its results of operations or financial position.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115 (SFAS 159), which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of SFAS 159 is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of SFAS 159 apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. The Company is currently evaluating what impact, if adopted, SFAS 159 may have on its results of operations or financial position.

(2) 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 $415.0 million, subject to customary closing adjustments (Panhandle I). The Panhandle I acquisition was financed with a combination of a private placement of our units (see Note 3) and borrowings under the Company s senior secured revolving credit facility (see Note 6).

On June 12, 2007, effective April 1, 2007, the Company completed the acquisition of certain oil and gas properties in the Texas Panhandle for $90.5 million, subject to customary closing adjustments (Panhandle II). The acquisition was financed with borrowings under the Company s senior secured revolving credit facility.

The following table presents the preliminary purchase prices for the Panhandle I and Panhandle II acquisitions based on preliminary estimates of fair value:

	Panhandle I	Panhandle II
	(in thousands)	
Cash	$ 411,287	$ 90,179
Estimated transaction costs	2,996	366
Estimated closing adjustments		(1,440)
	414,283	89,105
Fair value of liabilities assumed	1,706	1,034
Total purchase price	$ 415,989	$ 90,139

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

	Panhandle I	Panhandle II
	(in thousands)	
Oil and gas properties	$ 415,251	$ 89,495
Vehicles and buildings	738	
Receivables, net		644
	$ 415,989	$ 90,139

The preliminary purchase price allocations are based on discounted cash flows, independent appraisals of fixed assets, quoted market prices and estimates by management. The most significant assumptions are related to the estimated fair values assigned to proved oil and gas properties. To estimate the fair values of these properties, we utilized estimates of oil, gas and NGL reserves prepared by an independent engineering firm. 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 risk factors. There were no fair values assigned to unproved properties with the Texas Panhandle acquisitions. As noted, the purchase price allocations are preliminary; they are subject to final closing adjustments and will be finalized within one year of the acquisition dates.

The following unaudited pro forma financial information presents a summary of Linn s consolidated results of operations for the three and six months ended June 30, 2007 and 2006, assuming the Panhandle I and Panhandle II acquisitions had been completed as of January 1, 2006, including adjustments to reflect the allocation of the purchase prices to the acquired net assets. The pro forma financial information also assumes the Company s February 2007 private placement of units (see Note 3) was completed on January 1, 2006, since the private placement was contingent on completion of the Panhandle I acquisition. In addition, the pro forma financial information assumes that our California acquisitions of certain affiliated entities of Blacksand Energy, LLC and certain Oklahoma assets of the Kaiser-Francis Oil Company were completed as of January 1, 2006. The California and Oklahoma 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 Panhandle I and Panhandle II assets are included in the consolidated results of the Company as of February 1, 2007 and June 12, 2007, respectively. The pro forma financial information is not necessarily indicative of the results of operations if the acquisitions had been effective as of these dates.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Total revenues	$ 36,767	$ 68,179	$ 27,312	$ 171,077
Total operating expenses	$ 43,984	$ 34,921	$ 86,539	$ 70,234
Net income (loss)	$ (18,268)	$ 19,652	$ (86,148)	$ 73,197
Net income (loss) per unit:				
Units basic	$ (0.31)	$ 0.47	$ (1.64)	$ 1.78
Units diluted	$ (0.31)	$ 0.47	$ (1.64)	$ 1.77
Class C units basic	$	$ 0.47	$	$ 1.78
Class C units diluted	$	$ 0.47	$	$ 1.77

The 2006 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 3). 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 price of $39.0 million, subject to customary closing adjustments.

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.

On June 29, 2007, the Company entered into a definitive purchase agreement with Dominion Resources, Inc. and certain affiliates (Dominion) to acquire certain oil and gas properties in the Mid-Continent, in Oklahoma, Kansas and the Texas Panhandle (the Mid-Continent Acquisition) for $2.05 billion, subject to customary closing adjustments. The Company anticipates that the Mid-Continent Acquisition will close during the third quarter of 2007, subject to customary closing conditions, including the Company s receipt of financing. There can be no assurance that all of the conditions to closing will be satisfied. On June 29, 2007, the Company executed a unit purchase agreement for a private placement of $1.5 billion of units and Class D units to a group of institutional investors (see Note 3). In addition, on June 29, 2007, the Company received a commitment from two lenders under its credit facility (see Note 6) to provide funding of up to $1.9 billion contingent on closing of the Mid-Continent Acquisition. The Company intends to fund the Mid-Continent Acquisition with the net proceeds from the private placement, together with borrowings under the credit facility.

On August 2, 2007, the Company entered into a definitive purchase agreement to acquire certain oil and gas properties in the Texas Panhandle (the Panhandle III Acquisition) for $22.5 million, subject to customary closing adjustments. The Company anticipates that the Panhandle III Acquisition will close during the third quarter of 2007, subject to customary closing conditions.

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(3) Unitholders Capital

Pending Private Placement

On June 29, 2007, the Company executed a unit purchase agreement for a private placement of $1.5 billion of units to a group of institutional investors, consisting of 34,997,005 Class D units at a price of $30.97 per unit and 12,999,989 units at a price of $32.00 per unit (Pending Private Placement). Proceeds, net of expenses, will be used to fund the Mid-Continent Acquisition (see Note 2). The Pending Private Placement is expected to coincide with the closing of the Mid-Continent Acquisition and is subject to customary closing conditions, including the closing of the Mid-Continent Acquisition. There can be no assurance that all of the conditions to closing will be satisfied.

The Class D units will represent a class of equity securities that is entitled to a special quarterly distribution equal to 115% of the distribution received by the holders of units, has no voting rights other than as required by law and is subordinated to the units on dissolution and liquidation. The Class D units may convert into units if the conversion is approved by a vote of the Company s unitholders. The Company has agreed to hold a meeting of its unitholders to consider this proposal as soon as reasonably practicable, but no later than 120 days from the closing date. In connection with the Pending Private Placement, the Company also agreed to file a registration statement with the SEC covering the units and the Class D units, and that the registration statement would be declared effective by the SEC no later than 165 days following the closing.

June 2007 Private Placement

In June 2007, the Company closed its private placement of $260.0 million of units to a group of institutional investors, consisting of 7,761,194 units at a price of $33.50 per unit (the June 2007 Private Placement). Proceeds, net of expenses, were $255.4 million and were used to repay indebtedness under the Company s senior secured revolving credit facility (see Note 6). In connection with the June 2007 Private Placement, the Company also agreed to file a registration statement with the SEC covering the units, and that the registration statement would be declared effective by the SEC no later than November 13, 2007.

February 2007 Private Placement

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 February 2007 Private Placement). Proceeds, net of expenses, were $353.1 million. The proceeds from the February 2007 Private Placement were used to finance the Panhandle I acquisition and the acquisitions of certain gas properties in West Virginia (see Note 2).

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 February 2007 Private Placement, the Company agreed to file a registration statement with the SEC covering the units and the units underlying the Class C units, and that the registration statement would be declared effective by the SEC no later than 165 days following the closing. In June 2007, this deadline was extended to December 31, 2007.

October 2006 Private Placement

In connection with its October 2006 private placement of Class B units (the October 2006 Private Placement), the Company also agreed to file a registration statement with the SEC covering the units and the units underlying the Class B units, and that the registration statement would be declared effective by the SEC no later than 165 days following the closing. In June 2007, this deadline was extended to December 31, 2007.

Liquidated Damages

The Company could be required to pay purchasers liquidated damages specified in agreements pursuant to the October 2006, February 2007 and June 2007 Private Placements and the Pending Private Placement in the event the registration effectiveness deadlines are not met. The potential payments under the agreements are 0.25% of the gross proceeds 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. The Company does not believe it is probable that it will be required to make such payments; therefore, has not recorded a liability at this time. The Company will continue to monitor and assess its exposure in this matter; however, the Company does not currently expect payments, if any, under these agreements 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 company 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.

(4) Oil and Gas Capitalized Costs

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

	June 30, 2007	**December 31, 2006**
	(in thousands)	
Unproved properties	$ 8,216	$ 8,624
Proved properties:		
Leasehold, equipment and drilling	1,278,403	737,202
Gas compression plant and pipelines	84,205	20,812
	1,370,824	766,638
Less accumulated depletion, depreciation and amortization	(56,311)	(33,349)
Net capitalized costs	$ 1,314,513	$ 733,289

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(5) Property and Equipment

Property and equipment consists of the following:

	June 30, 2007 (in thousands)	December 31, 2006
Land	$ 320	$ 308
Buildings and leasehold improvements	4,798	2,759
Vehicles	4,581	3,097
Aircraft	5,890	5,890
Drilling equipment	11,707	8,611
Furniture and equipment	3,243	1,966
	30,539	22,631
Less accumulated depreciation	(3,387)	(1,877)
	$ 27,152	$ 20,754

Depreciation expense for the three and six months ended June 30, 2007, was approximately $0.8 million and $1.5 million, respectively. Depreciation expense for the three and six months ended June 30, 2006, was approximately $0.2 million and $0.4 million, respectively.

(6) Credit Facility

At June 30, 2007, the Company had an $800.0 million senior secured revolving credit facility with a maturity of August 2010, and a borrowing base of $765.0 million (Credit Facility). On June 29, 2007, the Company received a commitment from two lenders under its Credit Facility to provide funding of up to $1.9 billion contingent on closing of the Mid-Continent Acquisition (see Note 2). In July 2007, the Company incurred approximately $4.8 million in commitment fees that will be amortized over the life of this debt agreement.

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, 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 borrowings under 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 June 30, 2007 and December 31, 2006, the Credit Facility consisted of the following:

	June 30, 2007 (in thousands)		December 31, 2006	
Total (1)	$	476,000	$	425,750
Less current maturities				
	$	476,000	$	425,750

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(1) Variable rate of 6.625% and 7.125% at June 30, 2007 and December 31, 2006, respectively.

At June 30, 2007, the Company also had $5.0 million outstanding letters of credit, which reduce its borrowing availability under the Credit Facility. At June 30, 2007, available borrowing under the Credit Facility was $284.0 million.

(7) Long-term Notes Payable

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

	June 30, 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.	$	366		$	372	
Various notes for the purchase of vehicles and equipment, payable in monthly installments totaling approximately $96 and $88, as of June 30, 2007 and December 31, 2006, respectively, including interest. The interest rates range from 3.90%-9.11%. The notes are secured by the vehicles and equipment purchased and expire at various dates from 2007 through 2011. (1)	2,761			2,988		
	3,127			3,360		
Less current maturities	(999		)	(873		)
	$	2,128		$	2,487	

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(1) At June 30, 2007 and December 31, 2006, includes approximately $1.0 million of notes payable on which interest was imputed at 7.0%.

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As of June 30, 2007, maturities on the aforementioned long-term notes payable were as follows:

	(in thousands)
2007	$ 480
2008	946
2009	728
2010	471
2011	201
Thereafter	301
	$ 3,127

(8) 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 s customers consist primarily of major oil and gas purchasers and the Company generally does not require collateral.

A majority of the Company s largest customers are oil and gas producers, suppliers and operators. For the three and six months ended June 30, 2007, the Company s three largest customers represented approximately 28%, 22% and 13%, and 32%, 18% and 12%, respectively, of the Company s sales. For the three and six months ended June 30, 2006, the Company s two largest customers represented approximately 65% and 9%, and 68% and 10%, respectively, of the Company s sales.

At June 30, 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 June 30, 2007, trade accounts receivable from these customers represented approximately 24%, 18% 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 these customers represented approximately 41%, 22% and 16% of the Company s receivables.

(9) 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 or six months ended June 30, 2007 or 2006.

In June 2007, the Company entered into an agreement and paid $0.4 million to cancel future lease obligations totaling $1.1 million related to an office facility in Pennsylvania.

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.

In July 2007, the Company entered into hedging contracts to reduce oil and gas price risk exposures related to its pending Mid-Continent Acquisition (see Note 2). The contracts cover 40 Bcf of gas and 800,000 Bbls of oil per year for 2008 through 2012 and 7.8 Bcf of gas and 157,000 Bbls of oil for the fourth quarter of 2007. The contracts include deferred premium puts entered into in July 2007, for which the Company will pay the counterparty approximately $132.2 million in October 2007. In addition, the contracts include a deal-contingent option to enter into oil and gas swaps upon consummation of the Mid-Continent Acquisition for which the Company expects to pay commitment fees and premiums totaling approximately $71.9 million to the counterparty. The Company s commitment to enter into the swaps is contingent on the closing of the Mid-Continent Acquisition.

(10) Derivatives

The Company sells oil, gas and NGL 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. Oil derivatives are used to hedge oil and NGL sales.

Settled derivatives on gas production for the three and six months ended June 30, 2007, included a volume of 4,675 MMBtu and 9,369 MMBtu at an average contract price of $8.43 and $8.43, respectively. Settled derivatives on oil and NGL production for the three and six months ended June 30, 2007 included a volume of 500 MBbls and 892 MBbls at an average contract price of $68.71 and $69.16, respectively. The gas derivatives are settled based upon the closing NYMEX or Henry Hub 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 June 30, 2007 and represent, 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 (MMMBtu)	3,650	13,264	14,605	12,720	12,000
Average Price ($/MMBtu)	$ 8.76	$ 8.52	$ 8.01	$ 7.57	$ 7.48
Puts:					
Hedged Volume (MMMBtu)	4,029	7,053	6,960	6,960	6,960
Average Price ($/MMBtu)	$ 8.18	$ 8.07	$ 7.50	$ 7.50	$ 7.50
Total:					
Hedged Volume (MMMBtu)	7,679	20,317	21,565	19,680	18,960
Average Price ($/MMBtu)	$ 8.45	$ 8.36	$ 7.85	$ 7.55	$ 7.49

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	Year 2007	Year 2008	Year 2009	Year 2010	Year 2011
Oil Positions					
Fixed Price Swaps:					
Hedged Volume (MBbls)	250	560	580	550	525
Average Price ($/Bbl)	$ 75.83	$ 74.31	$ 73.87	$ 74.54	$ 61.58
Puts:					
Hedged Volume (MBbls)	750	1,550	1,550	1,700	1,750
Average Price ($/Bbl)	$ 66.33	$ 66.29	$ 66.29	$ 66.18	$ 65.00
Total**:**					
Hedged Volume (MBbls)	1,000	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:

	June 30, 2007	December 31, 2006
Outstanding notional amounts of gas hedges (MMMBtu)	88,201	31,503
Maximum number of months gas hedges outstanding	54	35
Outstanding notional amounts of oil hedges (MBbls)	9,765	8,700
Maximum number of months oil hedges outstanding	55	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.

In July 2007, the Company entered into additional hedging contracts to reduce oil and gas price risk exposures related to its pending Mid-Continent Acquisition (see Note 9).

(11) 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 in accordance with SFAS No. 128, *Earnings Per Share*.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(in thousands, except per unit amounts)			
Net income (loss)	$ (17,126)	$ 10,239	$ (84,973)	$ 32,216
Weighted average units outstanding:				
Basic units outstanding	59,293	27,830	52,413	27,056
Dilutive effect of unit equivalents (1)		264		269
Diluted units outstanding	59,293	28,094	52,413	27,325
Net income (loss) per unit:				
Units basic	$ (0.29)	$ 0.37	$ (1.62)	$ 1.19
Units diluted	$ (0.29)	$ 0.36	$ (1.62)	$ 1.18

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(1) Excludes the effect of average anti-dilutive common stock equivalents related to out-of-the-money unit options and warrants, and unvested restricted units of 514,406 and 398,755 for the three and six months ended June 30, 2007, respectively. Excludes the effect of average anti-dilutive common stock equivalents related to out-of-the-money unit options and unvested restricted units of 8,041 and 21,383 for the three and six months ended June 30, 2006, respectively. All equivalent units are anti-dilutive for the three and six months ended June 30, 2007 as the Company reported a net loss from operations.

(12) Unit-Based Compensation

Employee Grants

During the six months ended June 30, 2007, the Company granted an aggregate 400,500 restricted units to employees as part of its annual review of employee compensation and 118,500 restricted units to new employees of the Company with an aggregate fair value of approximately $17.0 million. In addition, during the six months ended June 30, 2007, the Company granted 108,000 unit options to new employees of the Company with a fair value of approximately $0.6 million. The majority of these restricted units and options vest ratably over three years.

For the three and six months ended June 30, 2007, the Company recorded unit-based compensation expense of approximately $3.1 million and $6.3 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. For the three and six months ended June 30, 2006, the Company recorded unit-based compensation expense of approximately $4.2 million and $9.9 million, respectively.

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 Panhandle I acquisition (see Note 2). 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 June 30, 2007, the aggregate fair value of the unit warrants was approximately $1.4 million and the expense was recognized over the five month term of the agreement through June 30, 2007. For the three and six months ended June 30, 2007, the Company recorded general and administrative expenses of approximately $0.9 million and $1.4 million, respectively, as a charge against income before income taxes.

(13) 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 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 June 30, 2007, deferred tax liabilities of approximately $0.8 million are recorded on the condensed consolidated balance sheets and deferred tax assets of $4.5 million, net of a valuation allowance of $3.7 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 June 30, 2007, the Company had no material uncertain tax positions.

(14) Related Party Transactions

During the three and six months ended June 30, 2006, the Company made payments of approximately $0.2 million to a company owned by one of our senior executives. The payments reflect reimbursement for maintenance and hourly usage fees for business use of an aircraft that was partially owned by the senior executive. These costs are included in general and administrative 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.

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 providing 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, gas and NGL reserves are currently located in three 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; and
- Mid-Continent, which includes the Sooner Trend of north central Oklahoma and the Texas portion of the Hugoton-Panhandle Field.

Acquisitions

The following table provides a summary of our significant oil and gas property acquisitions through the date of this report:

Year	# of Acquisitions	Gross Wells	Location	Aggregate Contract Price (in millions)
2003	4	498	West Virginia, Virginia, New York and Pennsylvania	$ 52.0
2004	2	698	Pennsylvania	25.9
2005	3	718	West Virginia and Virginia	124.5
2006	5	1,430	West Virginia, California and Oklahoma	451.7
2007	4	1,416	West Virginia and Texas	544.4
Completed	18	4,760		1,198.5
Pending*	2	2,624	Texas, Oklahoma and Kansas	2,072.5
	20	7,384		$ 3,271.0

* Includes the pending Mid-Continent Acquisition and Panhandle III Acquisition. The Company anticipates that these acquisitions will close during the third quarter of 2007, subject to customary closing conditions. See Note 2 in Notes to Condensed Consolidated Financial Statements for details about these pending acquisitions and acquisitions completed during the six months ended June 30, 2007.

From inception through June 30, 2007, we have completed 18 significant acquisitions of oil and gas properties and related gathering and pipeline assets for an aggregate purchase price of approximately $1.2 billion, with total proved reserves of approximately 815.5 Bcfe, or an acquisition cost of approximately $1.47 per Mcfe. Including preliminary estimates for the pending Mid-Continent Acquisition and Panhandle III Acquisition, our acquisitions would include proved reserves of approximately 1,588.8 Bcfe at an aggregate purchase price of approximately $3.3 billion, or an acquisition cost of approximately $2.06 per Mcfe.

Our acquisitions are 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.

Hedging Program

Our revenues are highly sensitive to changes in oil, gas and NGL prices and levels of production. We typically seek to hedge a significant portion of our anticipated future production volumes to reduce commodity price volatility risk. Managing this volatility, which we believe is likely to continue in the future, provides a longer-term stability

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of cash flows. Currently, we use fixed price swaps and puts to reduce our exposure to the volatility in oil, gas and NGL prices. As of the date of this report, we have hedged a significant portion of our expected production through 2012 using derivatives, which allows us to mitigate, but not eliminate, commodity price risk. See Item 3. Quantitative and Qualitative Disclosures About Market Risk for details about our derivatives in place through December 31, 2012.

Drilling and Operations

We concentrate our drilling activity on lower risk, development properties. The number, types, and location of wells we drill varies depending on our capital budget, the cost of each well, anticipated production and the estimated recoverable reserves attributable to each well. Historically, until 2007, most of our drilling has been in the Appalachian Basin. With our February 2007 Panhandle I and June 2007 Panhandle II acquisitions, our drilling program has been expanded to the Texas Panhandle and the Sooner Trend of Oklahoma. 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.

Higher oil, gas and NGL prices have led to higher demand for operating personnel and field supplies and services and have caused increases in the costs of those goods and services. In the Appalachian Basin, during 2006, the Company took delivery of its first two drilling rigs, with an additional rig delivered on March 30, 2007, which has reduced our reliance on contract rigs in that core area. The Company s drilling subsidiary performs certain services, including preparing and clearing well sites, providing drilling engineers, roustabouts and other personnel, for the Company s drilling program and for third parties. We focus our efforts on increasing oil, gas and NGL 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.

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. See Cautionary Statement below in this Item 2. for additional information about risks related to our Company.

Results of Operations - Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006

	Three Months Ended June 30, 2007	2006	Variance
	(in thousands)		
Revenues:			
Gas sales	$ 25,462	$ 13,126	$ 12,336
Oil sales	13,316	403	12,913
Natural gas liquid sales	10,439		10,439
Total oil, gas and natural gas liquid sales	49,217	13,529	35,688
Gain (loss) on oil and gas derivatives	(17,707)	12,895	(30,602)
Natural gas marketing revenues	1,139	1,346	(207)
Other revenues	1,139	204	935
Total revenues	$ 33,788	$ 27,974	$ 5,814
Expenses:			
Operating expenses	$ 14,714	$ 2,933	$ 11,781
Natural gas marketing expenses	879	1,189	(310)
General and administrative expenses	12,537	6,928	5,609
Depreciation, depletion and amortization	12,938	4,116	8,822
Total expenses	$ 41,068	$ 15,166	$ 25,902
Other income and (expenses)	$ (9,816)	$ (2,762)	$ (7,054)

	Three Months Ended June 30, 2007	2006	Percentage Increase (Decrease)
Production:			
Gas production (MMcf)	3,518	1,914	83.8 %
Oil production (MBbls)	251	7	*
Natural gas liquid production (MBbls)	203		
Total production (MMcfe)	6,245	1,956	219.3 %
Average daily production (MMcfe/d)	68.6	21.5	219.1 %
Weighted average realized prices: (1)			
Gas (Mcf)	$ 8.68	$ 9.91	(12.4)%
Oil (Bbl) (2)	$ 60.50	$ 58.03	4.3 %
Natural gas liquid (Bbl)	$ 52.63	$	
Total (Mcfe)	$ 9.03	$ 9.90	(8.8)%
Average unit costs per Mcfe of production (non-GAAP):			
Operating expenses	$ 2.36	$ 1.50	57.3 %
General and administrative expenses (3)	$ 1.37	$ 1.40	(2.1)%
Depreciation, depletion and amortization	$ 2.07	$ 2.10	(1.4)%

(1) Includes the effect of realized gains of $7.2 million and $5.8 million on derivatives for the three months ended June 30, 2007 and 2006, respectively.

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

(3) 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 June 30, 2007 and 2006 excludes approximately $4.0 million and $4.2 million, respectively, of unit-based compensation expense and unit warrant expense. General and administrative expenses including these amounts were $2.01 per Mcfe and $3.54 per Mcfe for the three months ended

June 30, 2007 and 2006, respectively.

* Not meaningful.

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Revenue

Gas, oil and NGL sales increased 264%, to approximately $49.2 million for the three months ended June 30, 2007, from $13.5 million for the three months ended June 30, 2006.

The increase in revenue from gas, oil and NGL sales was primarily attributable to increased production. Total production increased to 6,245 MMcfe during the three months ended June 30, 2007, from 1,956 MMcfe during the three months ended June 30, 2006. Gas production increased to 3,518 MMcf during the three months ended June 30, 2007, from 1,914 MMcf during the three months ended June 30, 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 72 wells during the three months ended June 30, 2007, compared to 55 wells during the three months ended June 30, 2006. Oil production increased to 251 MBbls during the three months ended June 30, 2007, from 7 MBbls during the during the three months ended June 30, 2006, due to the California, Panhandle I and Panhandle II acquisitions in August 2006, February 2007 and June 2007, respectively. The acquisitions in the Texas Panhandle also increased NGL production to 203 MBbls during the three months ended June 30, 2007, from zero during the comparative period of the prior year.

Hedging Activities

During the three months ended June 30, 2007, we entered into commodity pricing derivative contracts for approximately 133% of our gas production and 110% of our oil and NGL production, which resulted in realized gains of $7.2 million (revenues greater than we would have achieved at unhedged prices). The calculation of the percentage hedged for the three months ended June 30, 2007 includes an adjustment to reflect Panhandle I production, which was hedged, but was not included in the Company s reported production. It was instead recorded as a purchase price adjustment (see Note 2 in Notes to Condensed Consolidated Financial Statements). During the three months ended June 30, 2006, we entered into commodity pricing derivative contracts for approximately 95% of our gas production, which resulted in realized gains of $5.8 million. Unrealized losses on derivatives in the amount of $24.9 million for the three months ended June 30, 2007, and unrealized gains of $7.1 million for the three months ended June 30, 2006, were also recorded. Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract price on the derivative. During 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 prices for our production.

Expenses

Operating expenses include lease operating expenses, labor, field office expenses, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies and severance and ad valorem taxes. 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 $14.7 million for the three months ended June 30, 2007, from $2.9 million for the three months ended June 30, 2006, due to the increase in the number of producing wells as a result of the acquisitions completed in 2007 and in 2006 and the drilling of 72 wells in the three months ended June 30, 2007, and 472 wells from inception through June 30, 2007.

In addition, our average operating expenses per equivalent unit of production increased to $2.36 for the three months ended June 30, 2007, compared to $1.50 for the three months ended June 30, 2006, due to increased material and labor costs and the changing mix of production beginning in the third quarter of 2006 to include oil and NGL, which have higher operating costs than 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. General and administrative expenses increased to approximately $12.5 million for the three months ended June 30, 2007, from $6.9 million for the three months ended June 30, 2006. The increase in general and administrative expenses was primarily due to costs incurred to support our rapid growth through acquisitions and position the Company for future growth. In conjunction with expansion and development of our operations team, to date during 2007, we have hired approximately 40 employees and as a result, salaries and benefits expense increased approximately $1.7 million over the comparable quarter of 2006. We also incurred approximately $1.3 million in expenses for services performed by third-parties pursuant to a transition services agreement associated with the Panhandle I properties (see Note 2 in Notes to Condensed Consolidated Financial Statements). This services agreement terminated effective June 30, 2007. Costs to perform the necessary functions associated with being a large, growing, public company were $2.1 million during the second quarter of 2007, compared to $1.2 million during the second quarter of 2006. These costs include expenses for recruitment of key management team members, acquisition related data conversion and integration, public partnership tax reporting, audit fees, legal fees, proxy and printing costs and other professional fees, including costs related to our compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley Act). The Company is currently in the process of implementing and testing procedures and controls in order to comply with the Sarbanes-Oxley Act at December 31, 2007, and as such, expects these costs to continue throughout the remainder of the year. In addition, acquisition costs that are not eligible for capitalization, including internal and indirect costs for completed acquisitions, as well as direct costs associated with acquisition efforts that have not reached fruition, contributed to the increase. The increase in general and administrative expenses was partially offset by lower employee unit-based compensation expense, which decreased to $2.3 million (exclusive of amounts associated with the 40 new employees) during the three months ended June 30, 2007, from $4.2 million during the comparative quarter of 2006. Unit-based compensation expense incurred during the three months ended June 30, 2006 is higher compared to that incurred in the comparative period of 2007, primarily due to expense associated with unit awards granted in conjunction with the Company s IPO in January 2006. General and administrative expenses are presented net of approximately $0.1 million and $0.4 million during the three months ended June 30, 2007 and 2006, respectively, which represent expense reimbursements from other working interest owners.

Depreciation, depletion and amortization increased to approximately $12.9 million for the three months ended June 30, 2007, from $4.1 million for the three months ended June 30, 2006. Of this increase, approximately $5.8 million was as a result of depletion related to the California and Oklahoma acquisitions in the third quarter of 2006 and the Texas acquisitions in the first and second quarters of 2007. Although total depreciation, depletion and amortization increased in the second quarter of 2007 due to higher total production levels, the reserves in our recently acquired Texas, Oklahoma and California properties have lower depletion rates than our reserves in the Appalachian Basin. During the three months ended June 30, 2007 and 2006, the Company capitalized approximately $2.8 million and $0.6 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 June 30, 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.

Other income and (expenses) increased to a net expense of $9.8 million for the three months ended June 30, 2007, compared to a net expense of $2.8 million for the three months ended June 30, 2006, primarily due to increased interest expense from increased debt levels associated with acquisitions and drilling. Cash payments for interest increased to $10.3 million for the three months ended June 30, 2007, compared to $1.6 million for the three months ended June 30, 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 $0.3 million and $0.3 million for the three months ended June 30, 2007 and 2006, respectively. These amounts are non-cash gains.

Income tax was an expense of approximately $30,000 for the three months ended June 30, 2007, compared to a benefit of approximately $0.2 million for the three months ended June 30, 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 the three months ended June 30, 2007.

Results of Operations - Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

	Six Months Ended June 30, 2007 (in thousands)	2006	Variance
Revenues:			
Gas sales	$ 48,822	$ 29,133	$ 19,689
Oil sales	23,074	771	22,303
Natural gas liquid sales	16,525		16,525
Total oil, gas and natural gas liquid sales	88,421	29,904	58,517
Gain (loss) on oil and gas derivatives	(78,148)	37,141	(115,289)
Natural gas marketing revenues	2,917	2,564	353
Other revenues	3,229	493	2,736
Total revenues	$ 16,419	$ 70,102	$ (53,683)
Expenses:			
Operating expenses	$ 27,170	$ 5,927	$ 21,243
Natural gas marketing expenses	2,226	2,172	54
General and administrative expenses	23,158	16,398	6,760
Depreciation, depletion and amortization	24,789	7,816	16,973
Total expenses	$ 77,343	$ 32,313	$ 45,030
Other income and (expenses)	$ (20,387)	$ (5,647)	$ (14,740)

	Six Months Ended June 30, 2007	2006	Percentage Increase (Decrease)
Production:			
Gas production (MMcf)	6,892	3,712	85.7 %
Oil production (MBbls)	466	13	*
Natural gas liquid production (MBbls)	330		
Total production (MMcfe)	11,669	3,792	207.7 %
Average daily production (MMcfe/d)	64.5	21.0	207.1 %
Weighted average realized prices: (1)			
Gas (Mcf)	$ 8.54	$ 10.32	(17.2)%
Oil (Bbl) (2)	$ 60.21	$ 58.23	3.4 %
Natural gas liquid (Bbl)	$ 53.81	$	
Total (Mcfe)	$ 8.97	$ 10.30	(12.9)%
Average unit costs per Mcfe of production (non-GAAP):			
Operating expenses	$ 2.33	$ 1.56	49.4 %
General and administrative expenses (3)	$ 1.33	$ 1.18	12.7 %
Depreciation, depletion and amortization	$ 2.12	$ 2.06	2.9 %

(1) Includes the effect of realized gains of $16.3 million and $9.2 million on derivatives for the six months ended June 30, 2007 and 2006, respectively.

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

(3) 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 six months ended June 30, 2007 and 2006 excludes approximately $7.7 million and $9.9 million, respectively, of unit-based compensation expense and unit warrant expense. The measure for the six months ended June 30, 2006 excludes approximately $2.0 million of bonuses paid to certain executive officers in connection with our IPO. General and administrative expenses including these amounts were $1.98 per Mcfe and

$4.32 per Mcfe for the six months ended June 30, 2007 and 2006, respectively.

* Not meaningful.

Revenue

Gas, oil and NGL sales increased 196%, to approximately $88.4 million for the six months ended June 30, 2007, from $29.9 million for the six months ended June 30, 2006.

The increase in revenue from gas, oil and NGL sales was primarily attributable to increased production. Total production increased to 11,669 MMcfe during the six months ended June 30, 2007, from 3,792 MMcfe during the six months ended June 30, 2006. Gas production increased to 6,892 MMcf during the six months ended June 30, 2007, from 3,712 MMcf during the six months ended June 30, 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 113 wells during the six months ended June 30, 2007, compared to 84 wells during the six months ended June 30, 2006. Oil production increased to 466 MBbls during the six months ended June 30, 2007, from 13 MBbls during the during the six months ended June 30, 2006, due to the California, Panhandle I and Panhandle II acquisitions in August 2006, February 2007 and June 2007, respectively. The acquisitions in the Texas Panhandle also increased NGL production to 330 MBbls during the six months ended June 30, 2007, from zero during the comparative period of the prior year.

Hedging Activities

During the six months ended June 30, 2007, we entered into commodity pricing derivative contracts for approximately 124% of our gas production and 110% of our oil and NGL production, which resulted in realized gains of $16.3 million (revenues greater than we would have achieved at unhedged prices). The calculation of the percentage hedged for the six months ended June 30, 2007 includes an adjustment to reflect Panhandle I production, which was hedged, but was not included in the Company s reported production. It was instead recorded as a purchase price adjustment (see Note 2 in Notes to Condensed Consolidated Financial Statements). During the six months ended June 30, 2006, we entered into commodity pricing derivative contracts for approximately 97% of our gas production, which resulted in realized gains of $9.2 million. Unrealized losses on derivatives in the amount of $94.4 million for the six months ended June 30, 2007, and unrealized gains of $28.0 million for the six months ended June 30, 2006, were also recorded. Unrealized gains and losses result from changes in market valuations of derivatives as future commodity price expectations change compared to the contract price on the derivative. During the six months ended June 30, 2007, 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 prices for our production.

Expenses

Operating expenses include lease operating expenses, labor, field office expenses, vehicle expenses, supervision, transportation, minor maintenance, tools and supplies and severance and ad valorem taxes. 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 $27.2 million for the six months ended June 30, 2007, from $5.9 million for the six months ended June 30, 2006, due to the increase in the number of producing wells as a result of the acquisitions completed in 2007 and in 2006 and the drilling of 113 wells in the six months ended June 30, 2007, and 472 wells from inception through June 30, 2007.

In addition, our average operating expenses per equivalent unit of production increased to $2.33 for the six months ended June 30, 2007, compared to $1.56 for the six months ended June 30, 2006, due to increased material and labor costs and the changing mix of production beginning in the third quarter of 2006 to include oil and NGL, which have higher operating costs than 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. General and administrative expenses increased to approximately $23.2 million for the six months ended June 30, 2007, from $16.4 million for the six months ended June 30, 2006. The increase in general and administrative expenses was primarily due to costs incurred to support our rapid growth through acquisitions and position the Company for future growth. In conjunction with expansion and development of our operations team, to date during 2007, we have hired approximately 40 employees and as a result, salaries and benefits expense increased approximately $2.9 million as compared to the six months ended June 30, 2006. We also incurred approximately $1.8 million in expenses for services performed by third-parties pursuant to a transition services agreement associated with the Panhandle I properties (see Note 2 in Notes to Condensed Consolidated Financial Statements). This services agreement terminated effective June 30, 2007. Costs to perform the necessary functions associated with being a large, growing, public company were $6.1 million during the six months ended June 30, 2007, compared to $2.1 million during the six months ended June 30, 2006. These costs include expenses for relocation of the Company headquarters from Pittsburgh, Pennsylvania to Houston, Texas, recruitment of key management team members, acquisition related data conversion and integration, public partnership tax reporting, audit fees, legal fees, proxy and printing costs and other professional fees, including costs related to our compliance with the Sarbanes-Oxley Act. The Company is currently in the process of implementing and testing procedures and controls in order to comply with the Sarbanes-Oxley Act at December 31, 2007, and as such, expects these costs to continue throughout the remainder of the year. In addition, acquisition costs that are not eligible for capitalization, including internal and indirect costs for completed acquisitions, as well as direct costs associated with acquisition efforts that have not reached fruition, contributed to the increase. The increase in general and administrative expenses was partially offset by lower employee unit-based compensation expense, which decreased to $5.0 million (exclusive of amounts associated with the 40 new employees) during the six months ended June 30, 2007, from $9.9 million during the comparative period of 2006. Unit-based compensation expense incurred during the six months ended June 30, 2006 is higher compared to that incurred in the comparative period of 2007, primarily due to expense associated with unit awards granted in conjunction with the Company s IPO in January 2006. In addition, IPO bonuses of $2.0 million were paid to certain executive officers during the six months ended June 30, 2006. General and administrative expenses are presented net of approximately $0.2 million and $0.6 million during the six months ended June 30, 2007 and 2006, respectively, which represent expense reimbursements from other working interest owners.

Depreciation, depletion and amortization increased to approximately $24.8 million for the six months ended June 30, 2007, from $7.8 million for the six months ended June 30, 2006. Of this increase, approximately $10.6 million was as a result of depletion related to the California and Oklahoma acquisitions in the third quarter of 2006 and the Texas acquisitions in the first and second quarters of 2007. Although total depreciation, depletion and amortization increased in the six months ended June 30, 2007 due to higher total production levels, the reserves in our recently acquired Texas, Oklahoma and California properties have lower depletion rates than our reserves in the Appalachian Basin. During the six months ended June 30, 2007 and 2006, the Company capitalized approximately $4.7 million and $1.1 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 six months ended June 30, 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.

Other income and (expenses) increased to a net expense of $20.4 million for the six months ended June 30, 2007, compared to a net expense of $5.6 million for the six months ended June 30, 2006, primarily due to increase interest expense from increased debt levels associated with acquisitions and drilling. Cash payments for interest increased to $19.7 million for the six months ended June 30, 2007, compared to $5.0 million for the six months ended June 30, 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 $0.1 million and $0.7 million for the six months ended June 30, 2007 and 2006, respectively. These amounts are non-cash gains.

Income tax was an expense of approximately $3.7 million for the six months ended June 30, 2007, compared to a benefit of $74,000 for the six months ended June 30, 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 the six months ended June 30, 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 June 30, 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, 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 June 30, 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 six months ended June 30, 2007 was $19.4 million, compared to cash provided by operating activities of $14.1 million for the six months ended June 30, 2006. The decrease in cash provided by operating activities was primarily due to premiums paid for derivatives of approximately $53.0 million. These premiums relate to oil and gas derivatives on our projected production through December 31, 2011.

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 commodity 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 10 in Notes to Condensed Consolidated Financial Statements for details about our derivatives in place through December 31, 2011. See Item 3. Quantitative and Qualitative Disclosures About Market Risk, for details about our derivatives in place through December 31, 2012.

Statements of Cash Flows Investing Activities

Cash used in investing activities was $587.3 million for the six months ended June 30, 2007, compared to $65.8 million for the six months ended June 30, 2006. The increase in cash used in investing activities was primarily due to an increase in acquisition activity during the six months ended June 30, 2007, compared to the same period of the prior year.

The total cash used in investing activities for the six months ended June 30, 2007 includes $484.5 million for the Panhandle I and Panhandle II acquisitions and $38.6 million for the acquisitions of certain gas properties in West Virginia. See Note 2 in Notes to Condensed Consolidated Financial Statements for additional details. Other acquisitions, including acquisitions of additional working interests in our current wells, were approximately $16.2 million and property, plant and equipment purchases accounted for $7.5 million. The total for the six months ended June 30, 2007 also includes $43.5 million for the drilling and development of oil and gas properties.

Statements of Cash Flows Financing Activities

Cash provided by financing activities was $601.1 million for the six months ended June 30, 2007, compared to $44.3 million for the six months ended June 30, 2006.

The Company recorded gross proceeds of $620.0 million from two private placements of its units during the six months ended June 30, 2007 (see below). The proceeds, net of expenses of approximately $6.9 million paid through June 30, 2007, were used to finance the Panhandle I acquisition and the acquisitions of certain gas properties in West Virginia and to repay indebtedness under the Company s Credit Facility. During the six months ended June 30, 2007, total proceeds from borrowings under the Credit Facility were $308.0 million and total payments on the Credit Facility were $257.8 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 totaled approximately $22.7 million and 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 totaled approximately $30.0 million and was paid in May 2007.

In July 2007, the Company s Board of Directors declared a distribution of $0.57 per unit with respect to the second quarter of 2007, representing a 10% increase over the Company s distribution for the first quarter of 2007. The distribution will be paid in August 2007 to unitholders of record at the close of business on August 2, 2007. As previously announced, management currently intends to recommend to the Board of Directors a further increase in the quarterly cash distribution to $0.63 per unit, or $2.52 per unit on an annualized basis, beginning in the fourth fiscal quarter of 2007, contingent on the Company s pending Mid-Continent Acquisition.

Pending Private Placement

On June 29, 2007, the Company executed a unit purchase agreement for a private placement of $1.5 billion of units to a group of institutional investors, consisting of 34,997,005 Class D units at a price of $30.97 per unit and 12,999,989 units at a price of $32.00 per unit. Proceeds, net of expenses, will be used to fund the Mid-Continent Acquisition (see Note 2 in Notes to Condensed Consolidated Financial Statements). The Pending Private Placement is expected to coincide with the closing of the Mid-Continent Acquisition and is subject to customary closing conditions, including the closing of the Mid-Continent Acquisition. There can be no assurance that all of the conditions to closing will be satisfied.

The Class D units will represent a class of equity securities that is entitled to a special quarterly distribution equal to 115% of the distribution received by the holders of units, has no voting rights other than as required by law and is subordinated to the units on dissolution and liquidation. The Class D units may convert into units if the conversion is approved by a vote of the Company s unitholders. The Company has agreed to hold a meeting of its unitholders to consider this proposal as soon as reasonably practicable, but no later than 120 days from the closing date. In connection with the Pending Private Placement, the Company also agreed to file a registration statement with the SEC covering the units and the Class D units, and that the registration statement would be declared effective by the SEC no later than November 13, 2007.

June 2007 Private Placement

In June 2007, the Company closed its private placement of $260.0 million of units to a group of institutional investors, consisting of 7,761,194 units at a price of $33.50 per unit. Net proceeds were used to repay indebtedness under the Company s Credit Facility. In connection with the June 2007 Private Placement, the Company also agreed to file a registration statement with the SEC covering the units, and that the registration statement would be declared effective by the SEC no later than 165 days following the closing.

February 2007 Private Placement

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 proceeds from the February 2007 Private Placement were used to finance the Panhandle I acquisition and the acquisitions of certain gas properties in West Virginia. See Note 2 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 February 2007 Private Placement, the Company agreed to file a registration statement with the SEC covering the units and the units underlying the Class C units, and that the registration statement would be declared effective by the SEC no later than 165 days following the closing. In June 2007, this deadline was extended to December 31, 2007.

October 2006 Private Placement

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 closing. In June 2007, this deadline was extended to December 31, 2007.

Liquidated Damages

The Company could be required to pay purchasers liquidated damages specified in the agreements pursuant to the October 2006, February 2007 and June 2007 Private Placements and the Pending Private Placement. The potential payments under the agreements are 0.25% of the gross proceeds 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. The Company does not believe it is probable that it will be required to make such payments; therefore, has not recorded a liability at this time. The Company will continue to monitor and assess its exposure in this matter; however, the Company does not currently expect payments, if any, under these agreements 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 of 12,450,000 units representing limited liability company 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 June 30, 2007 the Company had an $800.0 million senior secured revolving credit facility with a maturity of August 2010, and a borrowing base of $765.0 million. On June 29, 2007, the Company received a commitment from two lenders under its Credit Facility to provide funding of up to $1.9 billion contingent on closing of the Mid-Continent

Acquisition. See Note 2 in Notes to Condensed Consolidated Financial Statements for additional details about the Mid-Continent Acquisition. In July 2007, the Company incurred approximately $4.8 million in commitment fees that will be amortized over the life of this debt agreement.

In connection with amendments, in the first six months of 2007, the Company paid fees of approximately $1.7 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 July 31, 2007, we had $284.9 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 borrowings under 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 June 30, 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. See Note 9 in Notes to Condensed Consolidated Financial Statements for discussion of the Company s oil and gas swaps entered into in July 2007.

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 June 30, 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:

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

For the second quarter of 2007 as compared to the second quarter of 2006, adjusted EBITDA increased 146%, from $14.9 million to $36.6 million. For the six months ended June 30, 2007 as compared to the comparable period of the prior year, adjusted EBITDA increased 129%, from $30.6 million to $70.1 million.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
	(in thousands)			
Net income (loss)	$ (17,126)	$ 10,239	$ (84,973)	$ 32,216
Plus:				
Net operating cash flow from acquisitions, effective date through closing date	1,923	712	4,693	712
Interest expense, net of amounts capitalized	9,952	2,696	19,865	5,335
Depreciation, depletion and amortization	12,938	4,116	24,789	7,816
Write-off of deferred financing fees and other	(255)	129	549	503
(Gain) loss on sale of assets	60	29	(885)	47
Accretion of asset retirement obligation	224	61	334	119
Unrealized (gain) loss on oil and gas derivatives	24,887	(7,055)	94,401	(27,978)

Unit-based compensation and unit warrant expense	3,951	4,196	7,691	9,876
IPO cash bonuses				2,039
Income tax (benefit) provision (1)	30	(193)	3,662	(74)
Adjusted EBITDA	$ 36,584	$ 14,930	$ 70,126	$ 30,611

(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 for the three and six months ended June 30, 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 six months ended June 30, 2007, was approximately $19.4 million and includes approximately $91.5 million unrealized losses on derivatives and $7.7 million unit-based compensation and unit warrant expense. Our net cash used by operating activities for the six months ended June 30, 2006, was approximately $14.1 million and includes $32.3 million unrealized gains on derivatives and $9.8 million unit-based compensation expense.

New Accounting Standards

There have been no accounting standards that materially affected the Company this period; however, see Note 13 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, gas and NGL reserves;
- realized oil, gas and NGL prices;
- production volumes;
- lease operating expenses, general and administrative expenses and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All of these types of statements, other than statements of historical fact included in this 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 our Quarterly Reports 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. Quantitive 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 oil, gas and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how 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, gas and NGL. Pricing for oil, gas and NGL 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 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 commodity 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 June 30, 2007, the fair value of hedges that settle during the next twelve months was an asset of approximately $29.4 million and a liability of approximately $4.5 million for a net asset of approximately $24.9 million, which we are owed by the counterparty. A 10% increase in the index oil and gas prices above the June 30, 2007 prices for the next twelve months would result in a reduction in the value of our hedges of approximately $16.8 million; conversely, a 10% decrease in the index oil and gas prices would result in an increase of approximately $21.3 million.

In July 2007, the Company entered into hedging contracts to reduce oil, gas and NGL price risk exposures related to its pending Mid-Continent Acquisition (see Note 2 in Notes to Condensed Consolidated Financial Statements). The contracts cover 40 Bcf of gas and 800,000 Bbls of oil per year for 2008 through 2012 and 7.8 Bcf of gas and 157,000 Bbls of oil for the fourth quarter of 2007. The contracts include deferred premium puts entered into in July 2007, for which the Company will pay the counterparty approximately $132.2 million in October 2007. In addition, the contracts include a deal-contingent option to enter into oil and gas price swaps upon consummation of the Mid-Continent Acquisition for which the Company expects to pay commitment fees and premiums totaling approximately $71.9 million to the counterparty. The Company s commitment to enter into the swaps is contingent on the closing of the Mid-Continent Acquisition.

The following tables summarize open derivative positions on annual production volumes as of July 31, 2007, including the hedging contracts entered into in July 2007 and the swap contracts contingent on closing of the Mid-Continent Acquisition discussed above:

	Year 2007	Year 2008	Year 2009	Year 2010	Year 2011	Year 2012
Gas Positions						
Fixed Price Swaps:						
Hedged Volume (MMMBtu)	7,361	40,005	41,346	39,461	38,741	26,741
Average Price ($/MMBtu)	$ 8.52	$ 8.41	$ 8.23	$ 8.10	$ 8.08	$ 8.35
Puts:						
Hedged Volume (MMMBtu)	6,536	20,312	20,219	20,219	20,219	13,259
Average Price ($/MMBtu)	$ 8.49	$ 8.55	$ 8.35	$ 8.35	$ 8.35	$ 8.80
Total:						
Hedged Volume (MMMBtu)	13,897	60,317	61,565	59,680	58,960	40,000
Average Price ($/MMBtu)	$ 8.50	$ 8.45	$ 8.27	$ 8.19	$ 8.17	$ 8.50

	Year 2007	Year 2008	Year 2009	Year 2010	Year 2011	Year 2012
Oil Positions						
Fixed Price Swaps:						
Hedged Volume (MBbls)	295	1,080	1,100	1,070	1,045	520
Average Price ($/Bbl)	$ 74.85	$ 73.44	$ 73.22	$ 73.55	$ 67.01	$ 72.50
Puts:						
Hedged Volume (MBbls)	695	1,830	1,830	1,980	2,030	280
Average Price ($/Bbl)	$ 67.24	$ 67.68	$ 67.68	$ 67.47	$ 66.43	$ 75.36
Total:						
Hedged Volume (MBbls)	990	2,910	2,930	3,050	3,075	800
Average Price ($/Bbl)	$ 69.51	$ 69.82	$ 69.76	$ 69.61	$ 66.63	$ 73.50

Interest Rate Risk

At June 30, 2007, we had long-term debt outstanding of $476.0 million under our Credit Facility, which incurred interest at floating rates in accordance the Credit Facility agreement. As of June 30, 2007, our rate based on the one-month LIBOR was approximately 6.625%. A 1% increase in the one-month LIBOR would result in an estimated $4.8 million increase in annual interest expense.

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 June 30, 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 June 30, 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 Securities Exchange Act of 1934 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 remediation status of our material weaknesses described below, our Chief Executive Officer and Chief Financial Officer continue to conclude that our disclosure controls and procedures were not entirely effective as of June 30, 2007. We believe we have taken the necessary steps to address the matters related to the material weaknesses described below and we conclude that the material weaknesses have been substantially remediated. Regarding review controls, including controls over significant computations involving estimates and judgment, we believe that these internal controls have not been implemented and operational for a sufficient period of time to demonstrate that they 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. We conclude that the material weaknesses have been substantially remediated. Regarding review controls, including controls over significant computations involving estimates and judgment, we believe that these internal controls have not been implemented and operational for a sufficient period of time to demonstrate they are operating effectively.

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.

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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.

In addition, to further enhance controls, during the three months ended June 30, 2007, the following improvements were implemented:

1. We strengthened controls over financially significant spreadsheets, including change, version, access, input/output and data controls.

2. We enhanced information technology (IT) controls, in areas including the general IT environment, access to programs and data and change management.

As noted above, we believe we have taken the necessary steps to address the matters related to the material weaknesses described above and we conclude that the material weaknesses have been substantially remediated. Regarding review controls, including controls over significant computations involving estimates and judgment, we believe that these internal controls have not been implemented and operational for a sufficient period of time to demonstrate that they are operating effectively.

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

The items noted above constitute the changes in our internal control over financial reporting, as defined in Rule 13(a)-15(f) under the Exchange Act, during the three months ended June 30, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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

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

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

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

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

- our ability to make working capital borrowings under our credit facility to pay distributions;
- the costs of acquisitions, if any;
- fluctuations in our working capital needs;
- timing and collectibility of receivables;
- restrictions on distributions contained in our credit facility;
- prevailing economic conditions; and
- the amount of cash reserves established by our Board of Directors for the proper conduct of our business.

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

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

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

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

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- an inability to transition and integrate successfully or timely the businesses we acquire;
- an inability to integrate data systems successfully or timely;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management s attention from other business concerns;
- increased demands on existing personnel and on our corporate structure;
- customer or key employee losses at the acquired businesses; and
- the failure to realize expected growth or profitability.

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

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

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

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

- the impact of energy conservation efforts;
- the proximity and capacity of pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

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

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

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

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

Producing oil and gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The overall rate of decline for our production will change if production from our existing wells declines in a different manner than we have estimated and can change when we drill additional wells, make acquisitions and under other circumstances. Thus, our future oil, 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, required to be used pursuant to SEC Regulation S-X Rule 4-10 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;

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- 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 six months ended June 30, 2007, Dominion Resources, Inc., ConocoPhillips and Duke Energy Corporation accounted for approximately 31%, 16% and 13%, respectively, of our total volumes, or 60% 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 April 5, 2007. The matters voted on at the meeting and the results are set forth below.

1. To vote upon (a) a change in terms of our Class C units to provide that each Class C unit will convert automatically into one of our units and (b) the issuance of 7,465,946 units upon such conversion.

Votes For		Votes Against or Withheld		Abstentions
27,484,956		56,028		49,587

Our 2007 Annual Meeting of Unitholders was held on June 19, 2007. Set forth below are descriptions of the matters voted on at the meeting and the results of the votes taken at the meeting.

1. To elect four directors to the Company s Board of Directors to serve until the 2008 Annual Meeting of Unitholders.

Name of Director		Votes For		Votes Against or Withheld
Michael C. Linn		41,008,089		52,960
George A. Alcorn		40,972,109		88,940
Terrence S. Jacobs		41,011,835		49,214
Jeffrey C. Swoveland		41,006,749		54,300

2. To ratify the appointment of KPMG LLP as independent auditor of the Company for the fiscal year ending December 31, 2007.

Votes For		Votes Against or Withheld		Abstentions
40,981,026		53,874		26,149

Item 5. Other Information

None.

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Item 6. Exhibits

Exhibit Number	**Description**
2 .1	Mid-Continent Onshore Package Purchase Agreement, dated June 29, 2007, between Dominion Exploration & Production, Inc., Dominion Oklahoma Texas Exploration & Production, Inc., LDNG Texas Holdings, LLC, and DEPI Texas Holdings, LLC, as Sellers, and Linn Energy, LLC, as Purchaser
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	Second Amendment to Second Amended and Restated Credit Agreement dated as of June 29, 2007, among Linn Energy, LLC, as borrower, BNP Paribas, as administrative agent, and the lenders party thereto
10 .10	Third Amendment to Second Amended and Restated Credit Agreement dated as of July 5, 2007, among Linn Energy, LLC, as borrower, BNP Paribas, as administrative agent, and the lenders party thereto

Exhibit Number	Description
10 .11	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 .12	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 .13	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 .14	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 .15	Unit Purchase Agreement, dated as of June 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 June 4, 2007)
10 .16	Registration Rights Agreement, dated as of June 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 June 4, 2007)
10 .17	Class D Unit and Unit Purchase Agreement, dated as of June 29, 2007, by and among the Company and the Purchasers named therein
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.

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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: August 14, 2007

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