SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

☑ **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

☐ **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: 000-50067

CROSSTEX ENERGY, L.P.
(Exact name of registrant as specified in its charter)

Delaware *(State of organization)*	**16-1616605** *(I.R.S. Employer Identification No.)*
2501 Cedar Springs **Dallas, Texas** *(Address of principal executive offices)*	**75201** *(Zip Code)*

(214) 953-9500
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

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

As of July 31, 2007, the Registrant had 22,046,294 common units, 4,668,000 subordinated units, 12,829,650 senior subordinated series C units and 3,875,340 senior subordinated series D units outstanding.

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CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

	June 30, 2007 (Unaudited)	December 31, 2006
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 256	$ 824
Accounts and notes receivable, net:		
Trade, accrued revenue and other	426,087	375,972
Related party	98	23
Fair value of derivative assets	13,856	23,048
Natural gas and natural gas liquids, prepaid expenses and other	17,356	10,468
Total current assets	457,653	410,335
Property and equipment, net of accumulated depreciation of $173,417 and $136,455, respectively	1,294,064	1,105,813
Fair value of derivatives assets	1,601	3,812
Intangible assets, net of accumulated amortization of $42,276 and $31,673, respectively	625,373	638,602
Goodwill	24,540	24,495
Other assets, net	10,530	11,417
Total assets	$ 2,413,761	$ 2,194,474
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable, drafts payable and accrued gas purchases	$ 422,160	$ 407,718
Fair value of derivative liabilities	9,899	12,141
Current portion of long-term debt	9,412	10,012
Other current liabilities	65,083	60,400
Total current liabilities	506,554	490,271
Long-term debt	1,124,412	977,118
Deferred tax liability	8,714	8,996
Minority interest in subsidiary	3,704	3,654
Fair value of derivative liabilities	1,532	2,558
Commitments and contingencies	—	—
Partners' equity	768,845	711,877
Total liabilities and partners' equity	$ 2,413,761	$ 2,194,474

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Unaudited) (In thousands, except per unit amounts)			
Revenues:				
Midstream	$ 984,669	$ 728,398	$ 1,794,467	$ 1,530,965
Treating	16,256	15,450	32,607	29,580
Profit on energy trading activities	991	807	1,594	1,230
Total revenues	1,001,916	744,655	1,828,668	1,561,775
Operating costs and expenses:				
Midstream purchased gas	910,061	676,370	1,661,943	1,432,821
Treating purchased gas	2,257	2,056	4,591	4,489
Operating expenses	29,956	22,840	57,313	44,801
General and administrative	14,849	10,919	26,882	22,275
Gain on sale of property	(971)	(160)	(1,821)	(109)
Loss (gain) on derivatives	(1,280)	3,925	(4,494)	1,766
Depreciation and amortization	25,509	18,708	50,495	35,758
Total operating costs and expenses	980,381	734,658	1,794,909	1,541,801
Operating income	21,535	9,997	33,759	19,974
Other income (expense):				
Interest expense, net	(18,620)	(11,890)	(35,947)	(20,402)
Other	218	(1)	268	—
Total other income (expense)	(18,402)	(11,891)	(35,679)	(20,402)
Income (loss) before minority interest and taxes	3,133	(1,894)	(1,920)	(428)
Minority interest in subsidiary	(30)	(101)	(50)	(182)
Income tax provision	(215)	(264)	(419)	(298)
Net income (loss) before cumulative effect of change in accounting principle	2,888	(2,259)	(2,389)	(908)
Cumulative effect of change in accounting principle	—	—	—	689
Net income (loss)	$ 2,888	$ (2,259)	$ (2,389)	$ (219)
General partner interest in net income	$ 4,538	$ 3,890	$ 8,707	$ 8,038
Limited partners' interest in net income (loss)	$ (1,650)	$ (6,149)	$ (11,096)	$ (8,257)
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit (see Notes 1(c) and 9):				
Basic and diluted common unit	$ (0.06)	$ (0.23)	$ (0.42)	$ (0.65)
Basic and diluted senior subordinated A unit (see Notes 1(c) and 9)	$ —	$ —	$ —	$ 5.31
Basic and diluted senior subordinated series C and D units (see Notes 1(c) and 9)	$ —	$ —	$ —	$ —
Net income (loss) per limited partners' unit:				
Basic and diluted common unit	$ (0.06)	$ (0.23)	$ (0.42)	$ (0.62)
Basic and diluted senior subordinated A unit (see Notes 1(c) and 9)	$ —	$ —	$ —	$ 5.31
Basic and diluted senior subordinated series C and D units (see Note 1(c) and 9)	$ —	$ —	$ —	$ —

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Six Months Ended June 30, 2007

(In thousands, except unit amounts)
(Unaudited)

	Common Units		Subordinated Units		Sr. Subordinated C Units		Sr. Subordinated D Units		General Partner Interest		Accumulated Other Comprehensive Income	Total
	$	Units	$	Units	$	Units	$	Units	$	Units		
Balance, December 31, 2006	$ 330,492	19,616,172	$ (6,402)	7,001,000	$ 359,319	12,829,650	—	—	$ 20,472	805,037	$ 7,996	$ 711,877
Proceeds from exercise of unit options	1,401	75,005	—	—	—	—	—	—	—	—	—	1,401
Net proceeds from issuance of senior subordinated D units	—	—	—	—	—	—	$ 99,942	3,875,340	—	—	—	99,942
Conversion of units	(3,872)	2,333,000	3,872	(2,333,000)	—	—	—	—	—	—	—	—
Conversion of restricted units to common units, net of units withheld for taxes	(186)	14,341	—	—	—	—	—	—	—	—	—	(186)
Capital contributions	—	—	—	—	—	—	—	—	2,771	80,912	—	2,771
Stock-based compensation	2,170	—	530	—	—	—	—	—	2,386	—	—	5,086
Distributions	(23,675)	—	(6,535)	—	—	—	—	—	(11,833)	—	—	(42,043)
Net income (loss)	(8,661)	—	(2,435)	—	—	—	—	—	8,707	—	—	(2,389)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	(3,277)	(3,277)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	(4,337)	(4,337)
Balance, June 30, 2007	$ 297,669	22,038,518	$ (10,970)	4,668,000	$ 359,319	12,829,650	$ 99,942	3,875,340	$ 22,503	885,949	$ 382	$ 768,845

See accompanying notes to condensed consolidated financial statements.

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CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
	(Unaudited) (In thousands)			
Net income (loss)	$ 2,888	$ (2,259)	$ (2,389)	$ (219)
Hedging gains or losses reclassified to earnings	(703)	(796)	(3,277)	1,440
Adjustment in fair value of derivatives	967	(2,516)	(4,337)	2,831
Comprehensive income (loss)	$ 3,152	$ (5,571)	$ (10,003)	$ 4,052

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Unaudited) (In thousands)	
Cash flows from operating activities:		
Net loss	$ (2,389)	$ (219)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation and amortization	50,495	35,758
Non-cash stock-based compensation	5,086	3,882
Cumulative effect of change in accounting principle	—	(689)
Gain on sale of property	(1,821)	(109)
Deferred tax expense	89	291
Minority interest in subsidiary	50	182
Non-cash derivatives (gain) loss	(314)	3,090
Amortization of debt issue costs	1,299	1,433
Changes in assets and liabilities, net of acquisition effects:		
Accounts receivable, accrued revenue and other	(50,190)	165,795
Natural gas and natural gas liquids and prepaid expenses	(7,105)	(7,424)
Accounts payable, accrued gas purchases and other accrued liabilities	52,576	(164,302)
Fair value of derivatives	835	—
Net cash provided by operating activities	48,611	37,688
Cash flows from investing activities:		
Additions to property and equipment	(229,857)	(97,885)
Acquisitions and asset purchases	—	(552,751)
Proceeds from sale of property	2,819	197
Net cash used in investing activities	(227,038)	(650,439)
Cash flows from financing activities:		
Proceeds from borrowings	751,500	995,892
Payments on borrowings	(604,806)	(699,706)
Decrease in drafts payable	(30,309)	(14,063)
Debt refinancing costs	(411)	(5,107)
Distribution to partners	(42,043)	(36,222)
Proceeds from exercise of unit options	1,401	2,824
Net proceeds from issuance of senior subordinated units	99,942	359,400
Contributions from partners	2,771	9,249
Restricted units withheld for taxes	(186)	—
Net cash provided by financing activities	177,859	612,267
Net decrease in cash and cash equivalents	(568)	(484)
Cash and cash equivalents, beginning of period	824	1,405
Cash and cash equivalents, end of period	$ 256	$ 921
Cash paid for interest	$ 37,223	$ 21,023

See accompanying notes to condensed consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements
June 30, 2007
(Unaudited)

(1) General

Unless the context requires otherwise, references to "we","us","our" or the "Partnership" mean Crosstex Energy, L.P. and its consolidated subsidiaries.

Crosstex Energy, L.P., a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids (NGLs). The Partnership connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of NGLs, transports natural gas and NGLs and ultimately provides natural gas to a variety of markets. In addition, the Partnership purchases natural gas and NGLs from producers not connected to its gathering systems for resale and sells natural gas and NGLs on behalf of producers for a fee.

Crosstex Energy GP, L.P. is the general partner of the Partnership. Crosstex Energy GP, L.P. is an indirect, wholly-owned subsidiary of Crosstex Energy, Inc. (CEI).

The accompanying condensed consolidated financial statements are prepared in accordance with the instructions to Form 10-Q, are unaudited and do not include all the information and disclosures required by generally accepted accounting principles for complete financial statements. All adjustments that, in the opinion of management, are necessary for a fair presentation of the results of operations for the interim periods have been made and are of a recurring nature unless otherwise disclosed herein. Certain reclassifications have been made to the consolidated financial statements for the prior years to conform to the current presentation. The results of operations for such interim periods are not necessarily indicative of results of operations for a full year. All significant intercompany balances and transactions have been eliminated in consolidation. These condensed consolidated financial statements should be read in conjunction with the financial statements and notes thereto included in our annual report on Form 10-K for the year ended December 31, 2006.

(a) Management's Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management of the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

(b) Long-Term Incentive Plans

Effective January 1, 2006, the Partnership adopted the provisions of SFAS No. 123R, "*Share-Based Compensation"* (FAS No. 123R) which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. The Partnership applied the provisions of Accounting Principles Board Opinion No. 25, "*Accounting for Stock Issued to Employees"* (APB No. 25), for periods prior to January 1, 2006.

The Partnership elected to use the modified-prospective transition method. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under FAS No. 123R. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with FAS No. 123R. The Partnership adjusted compensation cost for actual forfeitures as they occurred under APB No. 25 for periods prior to January 1, 2006. Under FAS No. 123R, the Partnership is required to estimate forfeitures in determining periodic compensation cost. The cumulative effect of the adoption of FAS No. 123R recognized on January 1, 2006 was an increase in net income of $0.7 million due to the reduction in previously recognized compensation costs associated with the estimation of forfeitures in determining the periodic compensation cost.

The Partnership and CEI each have similar share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plans awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Cost of share-based compensation charged to general and administrative expense	$ 2,406	$ 1,919	$ 4,429	$ 3,397
Cost of share-based compensation charged to operating expense	446	318	657	485
Total amount charged to income before cumulative effect of accounting change	$ 2,852	$ 2,237	$ 5,086	$ 3,882

Restricted Units

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the six months ended June 30, 2007 is provided below:

	Six Months Ended June 30, 2007	
Crosstex Energy, L.P. Restricted Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	336,504	$ 31.97
Granted	57,735	35.36
Vested	(19,500)	12.99
Forfeited	(8,876)	35.82
Non-vested, end of period	365,863	$ 33.43
Aggregate intrinsic value, end of period (in thousands)	$12,919	

The aggregate intrinsic value of units vested during the six month period ended June 30, 2007 was $0.7 million. As of June 30, 2007, there was $5.7 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.6 years.

Unit Options

The following weighted average assumptions were used for the Black-Scholes option pricing model for grants during the three and six months ended June 30, 2006 and 2007:

Crosstex Energy, L.P. Unit Options Granted:	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Weighted average distribution yield	5.75%	5.5%	5.75%	5.5%
Weighted average expected volatility	32.0%	32.9%	32.0%	33.0%
Weighted average risk free interest rate	4.44%	4.97%	4.44%	4.79%
Weighted average expected life	6 years	6 years	6 years	6 years
Weighted average contractual life	10 years	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$5.92	$7.37	$6.76	$7.45

A summary of the unit option activity for the six months ended June 30, 2007 is provided below:

Crosstex Energy, L.P. Unit Options:	Six Months Ended June 30, 2007 Number of Units	Six Months Ended June 30, 2007 Weighted Average Exercise Price
Outstanding, beginning of period	926,156	$ 25.70
Granted	345,599	37.31
Exercised	(75,005)	18.57
Forfeited	(47,797)	28.23
Expired	(4,789)	29.69
Outstanding, end of period	1,144,164	$ 29.55
Options exercisable at end of period	279,563	$ 27.44
Weighted average contractual term (years) end of period:		
Options outstanding	8.1	
Options exercisable	7.6	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$7,408	
Options exercisable	$2,254	

The total intrinsic value of unit options exercised during the six months ended June 30, 2006 and 2007 was $7.0 million and $1.4 million, respectively. The intrinsic value of unit options exercised during the three months ended June 30, 2006 and 2007 was $0.4 million and $0.9 million, respectively. The total fair value of options exercised during the six months ended June 30, 2006 and 2007 was $0.2 million and $0.3 million, respectively. The total fair value of options exercised for the three months ended June 30, 2006 and 2007 was $0.2 million and $0.1 million, respectively. As of June 30, 2007, there was $3.6 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 2.0 years.

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

CEI Restricted Shares

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. A summary of the restricted share activities for the six months ended June 30, 2007 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Six Months Ended June 30, 2007 Number of Shares	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	751,749	$ 17.03
Granted	50,528	29.42
Vested	(48,750)	9.70
Forfeited	(15,382)	20.59
Non-vested, end of period	738,145	$ 18.28
Aggregate intrinsic value, end of period (in thousands)	$21,207	

The aggregate intrinsic value of shares vested during the six month period ended June 30, 2007 was $1.4 million. As of June 30, 2007, there was $5.9 million of unrecognized compensation costs related to non-vested CEI restricted stock. The cost is expected to be recognized over a weighted average period of 1.6 years.

CEI Options

No CEI stock options were granted to, or exercised or forfeited by any officers or employees of the Partnership during the six months ended June 30, 2006 and 2007. The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of June 30, 2007:

Outstanding stock options (non exercisable)	30,000
Weighted average exercise price	$13.33
Aggregate intrinsic value	$461,999
Weighted average remaining contractual term	7.4 years

As of June 30, 2007, there was $46,000 of unrecognized compensation costs related to non-vested CEI stock options. The cost is expected to be recognized over a weighted average period of 2.3 years.

(c) Earnings per Unit and Dilution Computations

The Partnership's common units and subordinated units participate in earnings and distributions in the same manner for all historical periods and are therefore presented as a single class of common units for earnings per unit computations. The various series of senior subordinated units are also considered common securities, but because they do not participate in cash distributions during the subordination period are presented as separate classes of common equity. Each of the senior subordinated series of units were issued at a discount to the market price of the common units they are convertible into at the end of the subordination period. These discounts represent beneficial conversion features (BCFs) under EITF 98-5: *"Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios"*. Under EITF 98-5 and related accounting guidance, a BCF represents a non-cash distribution that is treated in the same way as a cash distribution for earnings per unit computations. Since the conversions of all the senior subordinated series units into common units are contingent (as described with the terms of such units) until the end of the subordination periods for each series of units, the BCF associated with each series of senior subordinated units is not reflected in earnings per unit until the end of such

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

subordination periods when the criteria for conversion are met. Following is a summary of the BCFs attributable to the senior subordinated units outstanding during 2006 and 2007 (in thousands):

	BCF	End of Subordination Period
Senior subordinated A units	$ 7,941	February 2006
Senior subordinated series C units	$ 121,112	February 2008
Senior subordinated series D units	$ 34,297	March 2009

The following table reflects the computation of basic earnings per limited partner units for the periods presented (in thousands except per unit amounts).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Limited Partners' interest in net income (loss)	$ (1,650)	$ (6,149)	$ (11,096)	$ (8,257)
Distributed earnings allocated to:				
Common units(1)	$ 15,290	$ 14,073	$ 30,210	$ 26,825
Senior subordinated A units(2)	—	—	—	7,941
Total distributed earnings	$ 15,290	$ 14,073	$ 30,210	$ 34,766
Undistributed loss allocated to:				
Common units(3)	$ (16,940)	$ (20,222)	$ (41,306)	$ (43,023)
Senior subordinated A units	—	—	—	—
Total undistributed earnings (loss)	$ (16,940)	$ (20,222)	$ (41,306)	$ (43,023)
Net income (loss) allocated to:				
Common units	$ (1,650)	$ (6,149)	$ (11,096)	$ (16,198)
Senior subordinated A units	—	—	—	7,941
Total limited partners' interest in net income (loss)	$ (1,650)	$ (6,149)	$ (11,096)	$ (8,257)
Cumulative effect of the change in accounting principle:				
Common units	$ —	$ —	$ —	$ 689
Senior subordinated A, C and D units	—	—	—	—
Total cumulative effect of the change in accounting principle	$ —	$ —	$ —	$ 689
Basic and diluted net income (loss) per unit before cumulative effect of change in accounting principle:				
Common units	$ (0.06)	$ (0.23)	$ (0.42)	$ (0.65)
Senior subordinated A units	$ —	$ —	$ —	$ 5.31
Senior subordinated series C and D units	$ —	$ —	$ —	$ —

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Basic and diluted cumulative effect of change in accounting principle per unit:				
Common units	$ —	$ —	$ —	$ 0.03
Senior subordinated A, C and D units	$ —	$ —	$ —	$ —
Basic and diluted net income (loss) per unit:				
Common units	$ (0.06)	$ (0.23)	$ (0.42)	$ (0.62)
Senior subordinated A units	$ —	$ —	$ —	$ 5.31
Senior subordinated series C and D units	$ —	$ —	$ —	$ —

(1) Represents distributions paid to common and subordinated unitholders.

(2) Represents BCF recognized at end of subordination period for senior subordinated A units.

(3) All undistributed earnings and losses are allocated to common units during the subordination period.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner common unit and senior subordinated A unit for the three and six months ended June 30, 2007 and 2006 (in thousands):

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Basic earnings per unit:				
Weighted average limited partner common units outstanding	26,685	26,572	26,664	26,064
Weighted average senior subordinated A units outstanding	—	—	—	1,495
Diluted earnings per unit:				
Weighted average limited partner units outstanding	26,685	26,572	26,664	26,064
Dilutive effect of restricted units issued	—	—	—	—
Dilutive effect of senior subordinated units	—	—	—	—
Dilutive effect of exercise of options outstanding	—	—	—	—
Diluted common units	26,685	26,572	26,664	26,064
Weighted average diluted senior subordinated A units outstanding	—	—	—	1,495

All common equivalents were antidilutive in the three and six months ended June 30, 2007 and 2006 because the limited partners were allocated a net loss in the periods.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note (4). The general partner’s share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

(excluding senior subordinated units) and the common units. The net income allocated to the general partner is as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Income allocation for incentive distributions	$ 5,767	$ 4,977	$ 11,264	$ 9,691
Stock-based compensation attributable to CEI's stock options and restricted shares	(1,195)	(961)	(2,330)	(1,484)
2% general partner interest in net loss	(34)	(126)	(227)	(169)
General Partner share of net income	$ 4,538	$ 3,890	$ 8,707	$ 8,038

(d) Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), *"Accounting for Uncertainty in Income Taxes"*. FIN 48 is an interpretation of FASB Statement No. 109, *"Accounting for Income Taxes"*. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. The Partnership adopted FIN 48 effective January 1, 2007. There was no impact to the Partnership's financial statements as a result of FIN 48.

On September 13, 2006, the Securities Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (SAB 108), which establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the company's financial statements and the related disclosures. SAB 108 requires the use of a balance sheet and an income statement approach to evaluate whether either of these approaches results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The Partnership adopted SAB 108 effective October 1, 2006 with no material impact on its financial statements.

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, "Fair Value Measurements" (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. While SFAS 157 does not add any new fair value measurements, it is intended to increase consistency and comparability of such measurement. The provisions of SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The adoption of this standard will not have a material impact on our results of operations, financial position or cash flows.

In February 2007, the FASB issued SFAS No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment to FASB Statement No. 115" (SFAS 159) permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, that the adoption of SFAS 159 will have on our financial statements.

(2) Significant Asset Purchases and Acquisitions

On June 29, 2006, the Partnership acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale (the North Texas Gathering (NTG) assets) from Chief Holdings LLC (Chief) for a purchase price of approximately $475.3 million (the Chief Acquisition). The NTG assets include five gathering systems, located in parts of Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties in Texas. The NTG assets also included a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. The gas gathering systems consisted of approximately 210 miles of existing gathering pipelines, ranging from four inches to twelve inches in diameter.

Simultaneously with the Chief Acquisition, the Partnership entered into a gas gathering agreement with Devon Energy Corporation (Devon) whereby the Partnership has agreed to gather, and Devon has agreed to dedicate and deliver, the future production on acreage that Devon acquired from Chief (approximately 160,000 net acres). Under the agreement, Devon has committed to deliver all of the production from the dedicated acreage into the gathering system, including production from current wells and wells that it drills in the future. The Partnership will expand the gathering system to reach the new wells as they are drilled. The agreement has a 15-year term and provides for a fixed gathering fee over the term. In addition to the Devon agreement, approximately 60,000 additional net acres were dedicated to the NTG assets under agreements with other producers.

The Partnership utilized the purchase method of accounting for the acquisition of the NTG assets with an acquisition date of June 29, 2006. The Partnership recognizes the gathering fee income received from Devon and other producers who deliver gas into the NTG assets as revenue at the time the natural gas is delivered. The purchase price and allocation thereof are as follows (in thousands):

Cash paid to Chief	$ 474,858
Direct acquisition costs	429
Total purchase price	$ 475,287
Assets acquired:	
Current assets	$ 18,833
Property, plant and equipment	115,728
Intangible assets	395,604
Liabilities assumed:	
Current liabilities	(54,878)
Total purchase price	$ 475,287

Intangibles relate primarily to the value of the dedicated and non-dedicated acreage attributable to the system, including the agreement with Devon, and are being amortized using the units of throughput method of amortization.

The Partnership financed the Chief Acquisition with borrowings of approximately $105.0 million under its bank credit facility, net proceeds of approximately $368.3 million from the private placement of senior subordinated series C units, including approximately $9.0 million of equity contributions from Crosstex Energy GP, L.P., the general partner of the Partnership and an indirect subsidiary of CEI, and $6.0 million of cash.

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Notes to Condensed Consolidated Financial Statements — (Continued)

Operating results for the Chief Acquisition have been included in the consolidated statements of operations since June 29, 2006. The following unaudited pro forma results of operations assume that the Chief Acquisition occurred on January 1, 2006 (in thousands, except per unit amounts):

	Pro Forma (Unaudited) Six Months Ended June 30, 2006
Revenue	$ 1,575,825
Net income (loss)	$ (4,836)
Net income (loss) per limited partner unit:	
Basic and diluted common units	$ (0.79)
Basic and diluted senior subordinated A unit	$ 5.31
Weighted average limited partners' units outstanding:	
Basic and diluted common units	26,064
Basic and diluted senior subordinated A unit	1,495

There are substantial differences in the way Chief operated the NTG assets during pre-acquisition periods and the way the Partnership operates these assets post-acquisition. Although the unaudited pro forma results of operations include adjustments to reflect the significant effects of the acquisition, these pro forma results do not purport to present the results of operations had the acquisition actually been completed as of January 1, 2006.

(3) Long-Term Debt

As of June 30, 2007 and December 31, 2006, long-term debt consisted of the following (in thousands):

	June 30, 2007	December 31, 2006
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at June 30, 2007 and December 31, 2006 were 7.15% and 7.20%, respectively	$ 640,000	$ 488,000
Senior secured notes, weighted average interest rates at June 30, 2007 and December 31, 2006 were 6.75% and 6.76%, respectively	493,824	498,530
Note payable to Florida Gas Transmission Company	—	600
	1,133,824	987,130
Less current portion	(9,412)	(10,012)
Debt classified as long-term	$ 1,124,412	$ 977,118

Credit Facility. As of June 30, 2007, the Partnership has a bank credit facility with a borrowing capacity of $1.0 billion that matures in June 2011. As of June 30, 2007, $765.8 million was outstanding under the bank credit facility, including $125.8 million of letters of credit, leaving approximately $234.2 million available for future borrowing.

In April 2007, the Partnership amended its bank credit facility to increase the maximum permitted leverage ratio for the fiscal quarter ending September 30, 2007 and each fiscal quarter thereafter. The maximum leverage ratio (total funded debt to consolidated earnings before interest, taxes, depreciation and amortization) is as follows (provided, however, that during an acquisition period, the maximum leverage ratio shall be increased by 0.50 to 1.00 from the otherwise applicable ratio set forth below):

- 5.25 to 1.00 for fiscal quarters through December 31, 2007;

- 5.00 to 1.00 for any fiscal quarter ending March 31, 2008 through September 2008;
- 4.75 to 1.00 for fiscal quarters ending December 31, 2008 and March 31, 2009; and
- 4.50 to 1.00 for any fiscal quarter ending thereafter.

Additionally, the credit facility provides that (i) if the Partnership or its subsidiaries incur unsecured note indebtedness, the leverage ratio will shift to a two-tiered structure and (ii) during periods where the Partnership has outstanding unsecured note indebtedness, the Partnership's leverage ratio cannot exceed 5.50 to 1.00 and the Partnership's senior leverage ratio cannot exceed 4.50 to 1.00. The other material terms and conditions of the credit facility remained unchanged.

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. See Note (5) to the financial statements for a discussion of interest rate swaps.

Senior Secured Notes. In April 2007, the Partnership amended the senior note agreement, effective as of March 30, 2007, to (i) provide that if the Partnership's leverage ratio at the end of any fiscal quarter exceeds certain limitations, the Partnership will pay the holders of the note an excess leverage fee based on the daily average outstanding principal balance of the notes during such fiscal quarter multiplied by certain percentages set forth in the senior note agreement; (ii) increase the rate of interest on each note by 0.25% if, at any given time during an acquisition period (as defined in the senior note agreement), the leverage ratio exceeds 5.25 to 1.00; (iii) cause the leverage ratio to shift to a two-tiered structure if the Partnership or its subsidiaries incur unsecured note indebtedness; and (iv) limit the Partnership's leverage ratio to 5.25 to 1.00 and the Partnership's senior leverage ratio to 4.25 to 1.00 during periods where the Partnership has outstanding unsecured note indebtedness. The other material items and conditions of the senior note agreement remained unchanged.

The Partnership was in compliance with all debt covenants as of June 30, 2007 and expects to be in compliance with debt covenants for the next twelve months.

(4) Partners' Capital

Issuance of Senior Subordinated Series D Units

On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests of the Partnership in a private offering for net proceeds of approximately $99.9 million. The senior subordinated series D units were issued at $25.80 per unit, which represented a discount of approximately 25% to the market value of common units on such date. The discount represented an underwriting discount plus the fact that the units will not receive a distribution nor be readily transferable for two years. Crosstex Energy GP, L.P. made a general partner contribution of $2.7 million in connection with this issuance to maintain its 2% general partner interest.

The senior subordinated series D units will automatically convert into common units representing limited partner interests of the Partnership on the first date on or after March 23, 2009 that conversion is permitted by its partnership agreement at a ratio of one common unit for each senior subordinated series D unit, subject to adjustment depending on the achievement of financial metrics in the fourth quarter of 2008. The Partnership's partnership agreement will permit the conversion of the senior subordinated series D units to common units once the subordination period ends or if the issuance is in connection with an acquisition that increases cash flow from operations per unit on a pro forma basis. If not able to convert on March 23, 2009, then the holders of such units will have the right to receive, after payment of the minimum quarterly distribution on the Partnership's common units but prior to any payment on the Partnership's subordinated units, distributions equal to 110% of the quarterly cash distribution amount payable on common units. The senior subordinated series D units are not entitled to distributions of available cash or allocation of net income/loss from the Partnership until March 23, 2009.

Cash Distributions

In accordance with the partnership agreement, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions will generally be made 98% to the common and subordinated unitholders (other than the senior subordinated unitholders) and 2% to the general partner, subject to the payment of incentive distributions to the extent that certain target levels of cash distributions are achieved. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $5.8 million and $5.0 million were earned by our general partner for the three months ended June 30, 2007 and June 30, 2006, respectively. Incentive distributions totaling $11.3 million and $9.7 million were earned in the six-month period ending June 30, 2007 and June 30, 2006, respectively. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter.

The Partnership has declared a second quarter 2007 distribution of $0.57 per unit to be paid on August 15, 2007 to unitholders of record as of August 2, 2007.

(5) Derivatives

Interest Rate Swaps

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. In March 2007, the Partnership entered into an interest rate swap covering a principal amount of $50.0 million under the credit facility for a period of three years. In November 2006, the Partnership also entered into an interest rate swap covering a principal amount of $50.0 million. The March 2007 interest rate swap fixes the three month LIBOR rate, prior to credit margin, at 4.875% on $50.0 million of related debt outstanding over the term of the swap agreement which expires on March 31, 2010. The November 2006 interest rate swap fixes the three month LIBOR rate, prior to credit margin, at 4.95% on $50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. The Partnership has elected to designate the March 2007 interest rate swap as a cash flow hedge for FAS 133 accounting treatment but has not designated the November 2006 interest rate swap as a cash flow hedge. Accordingly, unrealized gains and losses relating to the March 2007 interest rate swap are recorded in accumulated other comprehensive income until the related interest rate expense is recognized in earnings and unrealized gains and losses relating to the November 2006 interest rate swap are recorded through the consolidated statement of operations in gain on derivatives over the period hedged.

The components of (gain)/loss on derivatives in the Consolidated Statements of Operations relating to interest rate swaps are (in thousands):

	Three Months Ended June 30, 2007	Six Months Ended June 30, 2007
Change in fair value of derivatives that do not qualify for hedge accounting	$ (480)	$ (285)
Realized gains on derivatives	(111)	(181)
Ineffective portion of derivatives qualifying for hedge accounting	—	—
	$ (591)	$ (466)

No prior year comparisons are listed because interest rate swaps were entered into after June 30, 2006.

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Notes to Condensed Consolidated Financial Statements — (Continued)

The fair value of derivative assets and liabilities relating to interest rate swaps are as follows (in thousands):

	June 30, 2007	December 31, 2006
Fair value of derivative assets — current	$ 904	$ 89
Fair value of derivative liabilities — current	—	—
Net fair value of derivatives	$ 904	$ 89

At June 30, 2007 an unrealized gain of $0.5 million was recorded in accumulated other comprehensive income related to the interest rate swap dated March 2007.

Commodity Swaps

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge prices and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

The Partnership commonly enters into various derivative financial transactions which it does not designate as hedges. These transactions include “swing swaps”, “third party on-system financial swaps”, “marketing financial swaps”, “storage swaps”, “basis swaps” and “processing margin swaps”. Swing swaps are generally short-term in nature (one month), and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers, and simultaneously enters into the derivative transaction. Marketing financial swaps are similar to on-system financial swaps, but are entered into for customers not connected to the Partnership’s systems. Storage swaps transactions protect against changes in the value of gas that the Partnership has stored to serve various operational requirements. Basis swaps are used to hedge basis location price risk due to buying gas into one of our systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge frac spread risk at our processing plants relating to the option to process versus bypassing our equity gas.

The components of (gain)/loss on derivatives in the Consolidated Statements of Operations, excluding interest rate swaps, are (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Change in fair value of derivatives that do not qualify for hedge accounting	$ 607	$ 3,918	$ (76)	$ 2,999
Realized (gains) losses on derivatives	(1,331)	(159)	(4,016)	(1,324)
Ineffective portion of derivatives qualifying for hedge accounting	35	166	64	91
	$ (689)	$ 3,925	$ (4,028)	$ 1,766

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Notes to Condensed Consolidated Financial Statements — (Continued)

The fair value of derivative assets and liabilities, excluding interest rate swaps, are as follows (in thousands):

	June 30, 2007	December 31, 2006
Fair value of derivative assets — current	$ 12,952	$ 22,959
Fair value of derivative assets — long term	1,601	3,812
Fair value of derivative liabilities — current	(9,899)	(12,141)
Fair value of derivative liabilities — long term	(1,532)	(2,558)
Net fair value of derivatives	$ 3,122	$ 12,072

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at June 30, 2007 (all gas quantities are expressed in British Thermal Units and all liquid quantities are expressed in gallons). The remaining term of the contracts extend no later than December 2008 for derivatives, excluding third-party on-system financial swaps, and extend to June 2010 for third-party on-system financial swaps. The Partnership's counterparties to hedging contracts include BP Corporation, Total Gas & Power, Fortis, UBS Energy, Morgan Stanley and J. Aron & Co., a subsidiary of Goldman Sachs. Changes in the fair value of the Partnership's derivatives related to third-party producers' and customers' gas marketing activities are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings and the ineffective portion is recorded in earnings.

June 30, 2007

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Cash Flow Hedges:				
Natural gas swaps	99,000	NYMEX less a basis of $0.72 or fixed prices ranging from $7.355 to	July 2007 – December 2007	$ (181)
Natural gas swaps	(3,057,000)	$10.855 settling against various Inside FERC Index prices	July 2007 – December 2008	3,095
Total natural gas swaps designated as cash flow hedges				$ 2,914
Liquids swaps	(20,597,358)	Fixed prices ranging from $0.61 to $1.6275 settling against Mt. Belvieu Average of daily postings (non-TET)	July 2007 – March 2008	$ (3,077)
Total liquids swaps designated as cash flow hedges				$ (3,077)
Mark to Market Derivatives:				
Swing swaps	337,435	Prices ranging from Inside FERC Index less $0.0375 to Inside FERC	July 2007	$ 13
Swing swaps	(809,100)	Index plus $0.01 or fixed prices ranging from $6.458 to $6.88 settling against various Gas Daily Index prices	July 2007	(9)
Total swing swaps				$ 4
Physical offset to swing swap transactions	809,100	Prices of various Inside FERC Index prices settling against various Gas Daily Index prices	July 2007	—
Physical offset to swing swap transactions	(337,435)		July 2007	—
Total physical offset to swing swaps				$ —

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Notes to Condensed Consolidated Financial Statements — (Continued)

June 30, 2007

Transaction Type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Basis swaps	23,554,500	NYMEX less a basis of $0.785 to NYMEX plus a basis of $0.465 or	July 2007 – March 2008	$ (279)
Basis swaps	(26,399,500)	prices ranging from $7.585 to $10.505 settling against various Inside FERC Index prices.	July 2007 – March 2008	(294)
Total basis swaps				$ (573)
Physical offset to basis swap transactions	14,798,000	Prices ranging from Inside FERC Index less $0.15 to Inside FERC Index plus $0.085 or fixed prices	July 2007 – December 2007	$ (91,634)
Physical offset to basis swap transactions	(14,172,000)	ranging from $7.625 to $9.50 settling against various Inside FERC Index prices	July 2007 – October 2007	95,063
Total physical offset to basis swap transactions				$ 3,429
Third party on-system financial swaps	6,617,400	Fixed prices ranging from $5.704 to $11.57 settling against various Inside FERC Index prices	July 2007 – June 2010	$ (1,703)
Total third party on-system financial swaps				$ (1,703)
Physical offset to third party on-system transactions	(6,617,400)	Fixed prices ranging from $5.755 to $11.62 settling against various Inside FERC Index prices	July 2007 – June 2010	$ 2,151
Total physical offset to third party on-system swaps				$ 2,151
Processing margin (gas) swaps	304,767	Fixed prices ranging from $7.64 to $8.30 settling against various Inside FERC Index prices	July 2007 – November 2007	$ (329)
Total processing margin (gas) swaps				$ (329)
Processing margin (liquids) swaps	(3,032,011)	Fixed prices ranging from $0.7125 to $1.65 settling against Mt. Belvieu Average of daily postings (non-TET)	July 2007 – November 2007	$ (62)
Total processing margin (liquid) swaps				$ (62)
Storage swap transactions	(344,800)	Fixed prices ranging from $7.75 to $9.53 settling against various Inside FERC Index prices	July 2007 – February 2008	$ 355
Total storage swap transactions				$ 355
Natural gas liquid puts:				
Liquid put options (purchased)	40,579,728	Fixed prices ranging from $0.565 to $1.26 settling against Mt. Belvieu Average Daily Index	July 2007 – December 2007	$ 103
Liquid put options (sold)	(26,410,017)		July 2007 – December 2007	(90)
Total natural gas liquid puts				$ 13

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Notes to Condensed Consolidated Financial Statements — (Continued)

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits, and monitors the appropriateness of these limits on an ongoing basis.

Impact of Cash Flow Hedges

Natural Gas

For the six months ended June 30, 2007, net gains on cash flow hedge contracts of natural gas increased gas revenue by $2.7 million. For the six months ended June 30, 2006, net gains on cash flow hedge contracts of natural gas increased gas revenue by $0.4 million. For the three months ended June 30, 2007, net gains on cash flow hedge contracts of natural gas increased gas revenue by $1.2 million. For the three months ended June 30, 2006, net gains on cash flow hedge contracts of natural gas increased gas revenue by $0.9 million. As of June 30, 2007, an unrealized derivative fair value net gain of $2.9 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income (loss). Of this net amount, a $3.1 million gain is expected to be reclassified into earnings through June 2008. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

The settlement of cash flow hedge contracts related to July 2007 gas production increased gas revenue by approximately $0.4 million.

Liquids

For the six months ended June 30, 2007, net losses on cash flow hedge contracts of NGLs decreased liquids revenue by approximately $0.2 million. For the six months ended June 30, 2006, net gains on cash flow hedge contracts of NGLs increased liquids revenue by approximately $1.1 million. For the three months ended June 30, 2007, net losses on cash flow hedge contracts of NGLs decreased liquids revenue by $0.8 million. For the three months ended June 30, 2006, net losses on cash flow hedge contracts of NGLs decreased liquids revenue by $0.1 million. For the six months ended June 30, 2007, an unrealized derivative fair value loss of $3.1 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss) and the $3.1 million loss is expected to be reclassified into earnings through March 2008. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, puts, swing swaps, basis swaps, storage swaps and processing margin swaps are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as gain (loss) on derivatives in the consolidated statement of operations. The Partnership estimates the fair value of all of its energy trading contracts using prices actively quoted. The estimated fair value of energy trading contracts by maturity date was as follows (in thousands):

	Maturity Periods			
	Less than one year	One to two years	More than two years	Total fair value
June 30, 2007	$ 3,064	$ 154	$ 67	$ 3,285

(6) Transactions with Related Parties

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden) and treats gas for Erskine Energy Corporation (Erskine) and Approach Resources, Inc. (Approach). All three entities are affiliates of the Partnership by way of equity investments made by Yorktown Energy Partners, IV, L.P. and Yorktown Energy

Partners V, L.P., in Camden, Erskine and Approach. A director of both CEI and the Partnership is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships.

The table below lists related party transactions (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Treating Fees				
Camden	$ 568	$ 722	$ 1,143	$ 1,397
Erskine	249	347	526	704
Approach	—	119	—	239
Gas Purchases				
Camden	$ 4,833	$ 7,832	$ 12,491	$ 18,705

(7) Commitments and Contingencies

(a) Employment Agreements

Each member of senior management of the Partnership is a party to an employment contract with the general partner. The employment agreements provide each member of senior management with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

(b) Environmental Issues

The Partnership's Cow Island Gas Processing Facility, which was acquired in November 2005, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will reduce the remediation time as well as the costs associated with such remediation projects. The estimated remediation costs are expected to be approximately $0.5 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

(c) Other

The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

(8) Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the south Louisiana processing and liquids assets, the processing and transmission assets located in north and south Texas, the LIG pipelines and processing plants located in Louisiana, the Mississippi System, the Arkoma system located in Oklahoma and various other small systems. Also included in the Midstream division are the Partnership's energy trading operations. The operations in the Midstream segment are similar in the nature of the products and services,

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Notes to Condensed Consolidated Financial Statements — (Continued)

the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or though fixed monthly payments. The Seminole carbon dioxide processing plant located in Gaines County, Texas is included in the Treating division.

The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt financing costs.

Summarized financial information concerning the Partnership's reportable segments is shown in the following table.

	Midstream	Treating	Corporate	Totals
		(In thousands)		
Three months ended June 30, 2007:				
Sales to external customers	$ 984,669	$ 16,256	$ —	$ 1,000,925
Profit on energy trading activities	991	—	—	991
Purchased gas	(910,061)	(2,257)	—	(912,318)
Operating expenses	(24,451)	(5,505)	—	(29,956)
Segment profit	$ 51,148	$ 8,494	$ —	$ 59,642
Intersegment sales	$ 3,665	$ (3,665)	$ —	$ —
Gain (loss) on derivatives	$ 1,507	$ (4)	$ (223)	$ 1,280
Depreciation and amortization	$ (21,331)	$ (3,377)	$ (801)	$ (25,509)
Capital expenditures (excluding acquisitions)	$ 119,429	$ 2,590	$ 1,195	$ 123,214
Identifiable assets	$ 2,176,864	$ 208,228	$ 28,669	$ 2,413,761
Three months ended June 30, 2006:				
Sales to external customers	$ 728,398	$ 15,450	$ —	$ 743,848
Profit on energy trading activities	807	—	—	807
Purchased gas	(676,370)	(2,056)	—	(678,426)
Operating expenses	(18,219)	(4,621)	—	(22,840)
Segment profit	$ 34,616	$ 8,773	$ —	$ 43,389
Intersegment sales	$ 2,882	$ (2,882)	$ —	$ —
Gain (loss) on derivatives	$ (3,918)	$ (7)	$ —	$ (3,925)
Depreciation and amortization	$ (13,812)	$ (3,992)	$ (904)	$ (18,708)
Capital expenditures (excluding acquisitions)	$ 23,424	$ 3,248	$ 2,549	$ 29,221
Identifiable assets	$ 1,724,227	$ 185,184	$ 28,057	$ 1,937,468
Six months ended June 30, 2007:				
Sales to external customers	$ 1,794,467	$ 32,607	—	$ 1,827,074
Profit on energy trading activities	1,594	—	—	1,594
Purchased gas	(1,661,943)	(4,591)	—	(1,666,534)
Operating expenses	(46,557)	(10,756)	—	(57,313)
Segment profit	$ 87,561	$ 17,260	$ —	$ 104,821

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Notes to Condensed Consolidated Financial Statements — (Continued)

	Midstream	Treating	Corporate	Totals
	(In thousands)			
Intersegment sales	$ 7,350	$ (7,350)	$ —	$ —
Gain (loss) on derivatives	$ 4,855	$ (14)	$ (347)	$ 4,494
Depreciation and amortization	$ (41,121)	$ (7,303)	$ (2,071)	$ (50,495)
Capital expenditures (excluding acquisitions)	$ 210,799	$ 13,014	$ 2,747	$ 226,560
Identifiable assets	$ 2,176,864	$ 208,228	$ 28,669	$ 2,413,761
Six months ended June 30, 2006:				
Sales to external customers	$ 1,530,964	$ 29,581	$ —	$ 1,560,545
Profit on energy trading activities	1,230	—	—	1,230
Purchased gas	(1,432,821)	(4,489)	—	(1,437,310)
Operating expenses	(35,695)	(9,106)	—	(44,801)
Segment profit	$ 63,678	$ 15,986	$ —	$ 79,664
Intersegment sales	$ 5,918	$ (5,918)	$ —	$ —
Gain (loss) on derivatives	$ (1,759)	$ (7)	$ —	$ (1,766)
Depreciation and amortization	$ (27,457)	$ (6,662)	$ (1,639)	$ (35,758)
Capital expenditures (excluding acquisitions)	$ 76,563	$ 9,710	$ 3,768	$ 90,041
Identifiable assets	$ 1,724,227	$ 185,184	$ 28,057	$ 1,937,468

The following table reconciles the segment profits reported above to the operating income as reported in the consolidated statements of operations (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2007	2006	2007	2006
Segment profits	$ 59,642	$ 43,389	$ 104,821	$ 79,664
General and administrative expenses	(14,849)	(10,919)	(26,882)	(22,275)
Gain (loss) on derivatives	1,280	(3,925)	4,494	(1,766)
Gain (loss) on sale of property	971	160	1,821	109
Depreciation and amortization	(25,509)	(18,708)	(50,495)	(35,758)
Operating income	$ 21,535	$ 9,997	$ 33,759	$ 19,974

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements — (Continued)

(9) Immaterial Correction of Prior Period Financial Statements

In July 2007, the Partnership determined that its earnings per unit computations in its previously-issued financial statements for the three months ended March 31, 2006 and for each year-to-date period for periods ended June 30, 2006, September 30, 2006 and December 31, 2006 did not properly reflect the presentation of a BCF related to the senior subordinated units issued and the two-class method of earnings per unit presentation under EITF 03-6 as described in Note 1(c). The correction was not material to the Partnership's consolidated financial position or results of operations for the quarterly periods during 2006. The following table reflects the earnings per unit computations as previously reported and as corrected for each of the quarterly periods during 2006:

	Quarterly Periods in 2006:				
	First	Second	Third	Fourth	Total
As previously reported:					
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit:					
Basic and diluted common unit	$ (0.11)	$ (0.23)	$ (0.12)	$ (0.34)	$ (0.81)
Net income (loss) per limited partners' unit:					
Basic and diluted common unit	$ (0.08)	$ (0.23)	$ (0.12)	$ (0.34)	$ (0.78)
As corrected:					
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit:					
Basic and diluted common unit	$ (0.42)	$ (0.23)	$ (0.12)	$ (0.34)	$ (1.12)
Basic and diluted senior subordinated A unit	$ 5.31	—	—	—	$ 5.31
Net income (loss) per limited partners' unit:					
Basic and diluted common unit	$ (0.39)	$ (0.23)	$ (0.12)	$ (0.34)	$ (1.09)
Basic and diluted senior subordinated A unit	$ 5.31	—	—	—	$ 5.31

The correction has no impact on the Partnership's net income or loss or partners' equity for any periods.

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

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report.

Overview

We are a Delaware limited partnership formed on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and natural gas liquids (NGLs), as well as providing certain producer services, while our Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the six months ended June 30, 2007, 83% of our gross margin was generated in the Midstream division with the balance in the Treating division. We manage our operations by focusing on gross margin because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas and NGLs for a fee. We buy and sell most of our gas at a fixed relationship to the relevant index price so our margins are not significantly affected by changes in gas prices. In addition, we receive certain fees for processing based on a percentage of the liquids produced and enter into hedge contracts for our expected share of the liquids to protect our margins from changes in liquids prices. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

During the past five years we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2002 through June 30, 2007, we have invested over $2.0 billion to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems or processed at our processing facilities, and the volumes of NGLs handled at our fractionation facilities. Our Treating segment margins are largely a function of the number and size of treating plants in operation and fees earned for removing impurities from NGLs at a non-operated processing plant. We generate revenues from five primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants and fractionating and marketing the recovered NGLs;
- treating natural gas at our treating plants;
- recovering carbon dioxide and NGLs at a non-operated processing plant; and
- providing off-system marketing services for producers.

The bulk of our operating profits has historically been derived from the margins we realize for gathering and transporting natural gas through our pipeline systems. Generally, we buy gas from a producer, plant or transporter at either a fixed discount to a market index or a percentage of the market index. We then transport and resell the gas. The resale price is generally based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. See "Commodity Price Risk" below for a discussion of how we manage our business to reduce the impact of price volatility.

Processing and fractionation revenues are largely fee based. Our processing fees are usually based on either a percentage of the liquids volume recovered or a fixed fee per unit processed. Fractionation and marketing fees are generally a fixed fee per unit of product.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 27% and 37% of the operating income in our Treating division for the six months ended June 30, 2007 and 2006, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 49% and 47% of the operating income in our Treating division for the six months ended June 30, 2007 and 2006, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 24% and 16% of the operating income in our Treating division for the six months ended June 30, 2007 and 2006, respectively.

Operating expenses are costs directly associated with the operations of a particular asset. Among the most significant of these costs are those associated with direct labor and supervision and associated transportation and communication costs, property insurance, ad valorem taxes, repair and maintenance expenses, measurement and utilities. These costs are normally fairly stable across broad volume ranges, and therefore do not normally decrease or increase significantly in the short term with decreases or increases in the volume of gas moved through the asset.

Acquisitions

We have grown significantly through asset purchases in recent years, which creates many of the major differences when comparing operating results from one period to another. The most significant asset purchases since January 2006 were the acquisition of midstream assets from Chief Holding LLC (Chief) in June 2006, the acquisition of the Hanover Compression Company treating assets in February 2006 and the acquisition of the amine-treating business of Cardinal Gas Solutions Limited Partnership in October 2006.

On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems consist of approximately 210 miles of existing pipeline located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties, all of which are located in Texas. The acquired assets also include a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At closing, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. Since the date of acquisition through June 30, 2007, we connected approximately 190 new wells to our gathering system and increased the dedicated acres owned by other producers by approximately 37,000 net acres. In addition, we have a total of 46,000 horsepower of compression to handle the increased volumes and provide low-pressure gathering service. We also added two processing plants totaling 85,000 Mcf/d of processing capacity and two 30,000 Mcf/d dew point control plants (JT plants) in order to remove hydrocarbon liquids from growing gas streams, and we are building an additional 200,000 Mcf/d processing plant to be in operation in the third quarter 2007. We have also installed a 40 gallon per minute amine treating facility to provide carbon dioxide removal capability. We have increased total throughput on this gathering system from approximately 115 MMcf/d at the time of acquisition to 350 MMcf/d for the month of June 2007. We refer to the acquired assets and the other gathering assets we are building in the area as the North Texas Gathering (NTG) assets.

On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.7 million.

On October 3, 2006, we acquired the amine-treating business of Cardinal Gas Solutions Limited Partnership for $6.3 million. The acquisition added 10 dew point control plants and 50% of seven amine-treating plants to our plant portfolio. On March 28, 2007, we acquired the remaining 50% interest in the amine-treating plants for approximately $1.5 million.

Results of Operations

Set forth in the table below is certain financial and operating data for the Midstream and Treating divisions for the periods indicated.

	Three Months Ended June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Dollars in millions)			
Midstream revenues	$ 984.7	$ 728.4	$ 1,794.4	$ 1,531.0
Midstream purchased gas	(910.1)	(676.4)	(1,661.9)	(1,432.8)
Profit on energy trading activities	1.0	0.8	1.6	1.2
Midstream gross margin	75.6	52.8	134.1	99.4
Treating revenues	16.3	15.5	32.6	29.6
Treating purchased gas	(2.3)	(2.1)	(4.6)	(4.5)
Treating gross margin	14.0	13.4	28.0	25.1
Total gross margin	$ 89.6	$ 66.2	162.1	$ 124.5
Midstream Volumes (MMBtu/d):				
Gathering and transportation	2,201,000	1,409,000	2,028,000	1,367,000
Processing	2,021,000	1,970,000	1,965,000	1,870,000
Producer services	100,000	173,000	95,000	192,000
Plants in service at end of period	195	178	195	178

Three Months Ended June 30, 2007 Compared to Three Months Ended June 30, 2006

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $75.6 million for the three months ended June 30, 2007 compared to $52.8 million for the three months ended June 30, 2006, an increase of $22.8 million, or 43.1%. This increase was primarily due to system expansion projects, increased throughput and a favorable processing environment for NGLs. Profit on energy trading activities showed only a slight increase for the comparative period.

We acquired the North Texas Gathering (NTG) assets from Chief in June 2006. These assets combined with the North Texas Pipeline (NTPL) and related facilities contributed $17.0 million of gross margin growth during the three months ended June 30, 2007 over the same period in 2006. The NTPL and NTG assets accounted for $14.5 million of this increase. The processing facilities in the region contributed an additional $2.4 million of this gross margin increase. Operational improvements, system expansion and increased volume on the LIG system coupled with optimization and integration with the south Louisiana processing assets contributed a margin growth of $4.6 million during the second quarter of 2007 over the same period in 2006. Volume increases on the Mississippi and east Texas systems contributed gross margin growth of $1.1 million and $0.9 million, respectively.

Treating gross margin was $14.0 million for the three months ended June 30, 2007 compared to $13.4 million in the same period in 2006, an increase of $0.6 million, or 4.5%. Treating plants, dew point control plants, and related equipment in service increased from 178 plants at June 30, 2006 to 195 plants at June 30, 2007. Gross margin growth for the period is attributed to plant additions from inventory.

Operating Expenses. Operating expenses were $30.0 million for the three months ended June 30, 2007 compared to $22.8 million for the three months ended June 30, 2006, an increase of $7.1 million, or 31.2%. The $7.1 million increase in operating expenses primarily relates to the NTPL, the NTG assets and the north Louisiana operations expansion. Operating expenses included $0.4 million of stock-based compensation expense for the three months ended June 30, 2007 compared to $0.3 million of stock-based compensation expense for the three months ended June 30, 2006.

General and Administrative Expenses. General and administrative expenses were $14.8 million for the three months ended June 30, 2007 compared to $10.9 million for the three months ended June 30, 2006, an increase of

$3.9 million, or 36.0%. A substantial part of the increased expenses resulted primarily from staffing related costs of $2.2 million. The staff additions associated with the requirements of the NTG assets, NTPL and the expansion in north Louisiana accounted for the majority of the $2.2 million increase. General and administrative expenses included stock-based compensation expense of $2.4 million and $1.9 million for the three months ended June 30, 2007 and 2006, respectively. The $0.5 million increase in stock-based compensation primarily relates to increased staffing and additional grants for comparative periods.

Gain on Sale of Property. The $1.0 million gain on property sold during the three months ended June 30, 2007 primarily relates to the disposition of unused catalyst material.

Gain/Loss on Derivatives. We had a gain on derivatives of $1.3 million for the three months ended June 30, 2007 compared to a loss of $3.9 million for the three months ended June 30, 2006. The gain in 2007 includes a net gain of $1.5 million associated with our basis swaps (including $1.9 million of realized gains), gains of $0.4 million associated with our storage financial transactions and a gain of $0.6 million associated with our interest rate swaps. These gains were partially offset by a loss of $1.0 million associated with our processing margin hedges (including $0.7 million of realized losses) and loss of $0.2 million related to our puts and ineffectiveness. The loss in 2006 includes a loss of $2.7 million on our puts acquired in 2005 related to the acquisition of the south Louisiana assets and a loss of $1.4 million associated with our basis swaps offset by net gains of $0.2 million associated with our third-party on-system and storage financial transactions and ineffectiveness. As of June 30, 2007, the fair value of the puts was less than $0.1 million.

Depreciation and Amortization. Depreciation and amortization expenses were $25.5 million for the three months ended June 30, 2007 compared to $18.7 million for the three months ended June 30, 2006, an increase of $6.8 million, or 36.4%. Midstream depreciation and amortization increased $4.2 million due to the acquisition of the NTG assets and $1.6 million due to the NTPL, which was placed in service in April 2006. The north Louisiana expansion generated an increase in depreciation between periods of $1.6 million.

Interest Expense. Interest expense was $18.6 million for the three months ended June 30, 2007 compared to $11.9 million for the three months ended June 30, 2006, an increase of $6.7 million, or 56.6%. The increase relates primarily to an increase in debt outstanding and to higher interest rates between three-month periods (weighted average rate of 7.0% in the 2007 period compared to 6.8% in the 2006 period).

Six Months Ended June 30, 2007 Compared to Six Months Ended June 30, 2006

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $134.1 million for the six months ended June 30, 2007 compared to $99.4 million for the six months ended June 30, 2006, an increase of $34.7 million, or 35%. This increase was primarily due to system expansion projects, increased throughput and a favorable processing environment for NGLs. Profit on energy trading activities showed only a slight increase for the comparative period.

We acquired the bulk of the NTG assets from Chief in June 2006. These assets combined with the NTPL and related facilities contributed $30.9 million of gross margin growth during the six months ended June 30, 2007 over the same period in 2006. The NTPL and NTG assets accounted for $26.1 million of this increase. The processing facilities in the region contributed an additional $3.7 million of this gross margin increase. Operational improvements, system expansion and increased volume on the LIG system coupled with optimization and integration with the south Louisiana processing assets contributed a margin growth of $3.8 million during the second quarter of 2007 over the same period in 2006.

Treating gross margin was $28.0 million for the six months ended June 30, 2007 compared to $25.1 million for the same period in 2006, an increase of $2.9 million, or 11.6%. Treating plants, dew point control plants, and related equipment in service increased from 178 plants at June 30, 2006 to 195 plants at June 30, 2007. Gross margin growth for the period is attributed to plant additions from inventory.

Operating Expenses. Operating expenses were $57.3 million for the six months ended June 30, 2007 compared to $44.8 million for the six months ended June 30, 2006, an increase of $12.5 million, or 27.9%. The increase in operating expenses primarily reflects the operations of the NTPL, the NTG assets and the north Louisiana expansion. Operating expenses included $0.7 million of stock-based compensation expense for the six months ended June 30, 2007 compared to $0.5 million of stock-based compensation expense for the six months ended June 30, 2006.

General and Administrative Expenses. General and administrative expenses were $26.9 million for the six months ended June 30, 2007 compared to $22.3 million for the six months ended June 30, 2006, an increase of $4.6 million, or 20.7%. The staff additions associated with the requirements of the NTPL the NTG assets and the expansion in north Louisiana accounted for $2.6 million in increased costs. General and administrative expenses included stock-based compensation expense of $4.4 million and $3.4 million for the six months ended June 30, 2007 and 2006, respectively. The $1.0 million increase in stock-based compensation primarily relates to restricted stock and unit grants and increased headcount between comparative periods. Other expenses, including audit, legal and other consulting fees, office rent, travel and training accounted for $1.0 million of the increase.

Gain on Sale of Property. The $1.8 million gain on sale of property for the six months ended June 30, 2007 consists of the disposition of unused catalyst material for $1.0 million and the sale of a treating plant for $0.9 million, offset by losses on disposition of other treating equipment.

Gain/Loss on Derivatives. We had a gain on derivatives of $4.5 million for the six months ended June 30, 2007 compared to a loss of $1.8 million for the six months ended June 30, 2006. The gain in 2007 includes a net gain of $5.2 million associated with our basis swaps (including $2.7 million of realized gains), gains of $0.3 million associated with our third-party on-system and storage financial transactions and a gain of $0.5 million associated with our interest rate swaps. These were partially offset by a loss of $0.8 million on our puts acquired in 2005 related to the acquisition of the south Louisiana assets and losses of $0.7 million associated with our processing margin hedges (including $0.2 million of realized losses) and ineffectiveness. The loss in 2006 includes a loss of $3.8 million on our puts and a loss of $0.5 million associated with our basis swaps offset in part by gains of $2.5 million associated with our third-party on-system and storage financial transactions (including $1.3 million realized gains). As of June 30, 2007, the fair value of the puts was less than $0.1 million.

Depreciation and Amortization. Depreciation and amortization expenses were $50.5 million for the six months ended June 30, 2007 compared to $35.8 million for the six months ended June 30, 2006, an increase of $14.7 million, or 41.2%. Midstream depreciation and amortization expense increased $7.8 million due to the NTG assets and $3.8 million due to the NTPL, which was placed in service in April 2006. The north Louisiana expansion, which was placed in service in April 2007, generated an increase in depreciation between periods of $1.9 million and the remaining increase relates to other assets with a combined increase of $1.2 million.

Interest Expense. Interest expense was $35.9 million for the six months ended June 30, 2007 compared to $20.4 million for the six months ended June 30, 2006, an increase of $15.5 million. The increase relates primarily to an increase in debt outstanding as rates were equivalent for the comparative periods.

Cumulative Effect of Accounting Change. The Partnership recorded $0.7 million of income for the cumulative adjustment to recognize the required change in reporting stock-based compensation under FASB Statement No. 123R which was effective January 1, 2006.

Critical Accounting Policies

Information regarding the Partnership's Critical Accounting Policies is included in Item 7 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2006.

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $48.6 million for the six months ended June 30, 2007 compared to $37.7 million for the six months ended June 30, 2006. Income before non-cash income and expenses was $52.5 million in 2007 and $43.6 million in 2006. Changes in working capital used $3.9 million in cash flows from operating activities in 2007 as compared to $5.9 million in cash flows used by working capital changes in 2006.

Net cash used in investing activities was $227.0 million and $650.4 million for the six months ended June 30, 2007 and 2006, respectively. Net cash invested in Midstream assets was $208.9 million for the six months ended

June 30, 2007 compared to $589.6 million for the same time period in 2006 including $475.4 million related to the acquisition of assets from Chief. Net cash invested in Treating assets for the six months ended June 30, 2007 was $13.0 million compared to $63.2 million for the same period in 2006 including $51.5 million related to the acquisition of Hanover assets.

Net cash provided by financing activities was $177.9 million for the six months ended June 30, 2007 compared to $612.3 million provided by financing activities for the six months ended June 30, 2006. Net cash provided by financing activities for the six months ended June 30, 2007 included $102.6 million from the issuance of senior subordinated series D units, including the general partner contribution and net of issuance costs, and net bank borrowings of $146.7 million. Net cash provided by financing activities for the period ended June 30, 2006 included $368.4 million from the issuance of senior subordinated series C units, including the general partner contribution, net borrowings under our credit facility of $238.0 million and net borrowings under our senior secured notes of $58.2 million. Distributions to partners totaled $42.0 million in the first half of 2007 compared to $36.2 million in the first half of 2006. Drafts payable decreased by $30.3 million for the six months ended June 30, 2007 as compared to a decrease in drafts payable of $14.1 million for the six months ended June 30, 2006. In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility.

Working Capital Deficit. We had a working capital deficit of $48.9 million as of June 30, 2007, primarily due to drafts payable of $17.6 million and accrued liabilities of $59.2 million, including $25.3 million attributable to accrued property development costs. As discussed under “Cash Flows” above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank. We borrow money under our $1.0 billion bank credit facility to fund checks as they are presented. As of June 30, 2007, we had $234.2 million of available borrowings under this facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of June 30, 2007.

March 2007 Sale of Senior Subordinated Series D Units. On March 23, 2007, we issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests in a private offering for net proceeds of approximately $99.9 million. The senior subordinated series D units were issued at $25.80 per unit, which represented a discount of approximately 25% to the market value of common units on such date. The discount represented an underwriting discount plus the fact that the units will not receive a distribution nor be readily transferable for two years. Crosstex Energy GP, L.P. made a general partner contribution of $2.7 million in connection with this issuance to maintain its 2% general partner interest. The senior subordinated series D units will automatically convert into common units representing limited partner interests on the first date on or after March 23, 2009 that conversion is permitted by our partnership agreement at a ratio of one common unit for each senior subordinated series D unit, subject to adjustment depending on the achievement of financial metrics in the fourth quarter of 2008. The senior subordinated series D units are not entitled to distributions of available cash or allocations of net income/loss from us until March 23, 2009.

Capital Requirements of the Partnership. The natural gas gathering, transmission, treating and processing businesses are capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to be:

- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain existing operating capacity of our assets and to extend their useful lives, or other capital expenditures which do not increase our cash flows; and
- growth capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity, processing plants or treating plants, and to construct or acquire new pipelines, processing plants or treating plants, and expenditures made in support of that growth.

Given our objective of growth through acquisitions and large capital expansions, we anticipate that we will continue to invest significant amounts of capital to grow and to build and acquire assets. We actively consider a variety of assets for potential development and acquisitions.

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.57 per quarter and to fund a portion of our anticipated capital expenditures through June 30, 2008. Total capital expenditures for the remainder of 2007 are estimated to be approximately $145.0 million. We expect to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Indebtedness

As of June 30, 2007 and December 31, 2006, long-term debt consisted of the following (in thousands):

	June 30, 2007	December 31, 2006
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin, interest rates (per the facility) at June 30, 2007 and December 31, 2006 were 7.15% and 7.20%, respectively	$ 640,000	$ 488,000
Senior secured notes, weighted average interest rate at June 30, 2007 and December 31, 2006 were 6.75% and 6.76%, respectively	493,824	498,530
Note payable to Florida Gas Transmission Company	—	600
	$ 1,133,824	987,130
Less current portion	(9,412)	(10,012)
Debt classified as long-term	$ 1,124,412	$ 977,118

The above table does not include any physical or financial contract purchase commitments for natural gas.

Credit Facility. As of June 30, 2007, we had a bank credit facility with a borrowing capacity of $1.0 billion that matures in June 2011. As of June 30, 2007, $765.8 million was outstanding under the bank credit facility, including $125.8 million of letters of credit, leaving approximately $234.2 million available for future borrowing.

In April 2007, we amended our bank credit facility to increase the maximum permitted leverage ratio for the fiscal quarter ending September 30, 2007 and each fiscal quarter thereafter. The maximum leverage ratio (total funded debt to consolidated earnings before interest, taxes, depreciation and amortization) is as follows (provided, however, that during an acquisition period, the maximum leverage ratio shall be increased by 0.50 to 1.00 from the otherwise applicable ratio set forth below):

- 5.25 to 1.00 for fiscal quarters through December 31, 2007;
- 5.00 to 1.00 for any fiscal quarter ending March 31, 2008 through September 2008;
- 4.75 to 1.00 for fiscal quarters ending December 31, 2008 and March 31, 2009; and
- 4.50 to 1.00 for any fiscal quarter ending thereafter.

Additionally, the credit facility provides that (i) if we or our subsidiaries incur unsecured note indebtedness, the leverage ratio will shift to a two-tiered structure and (ii) during periods where we have outstanding unsecured note indebtedness, our leverage ratio cannot exceed 5.50 to 1.00 and our senior leverage ratio cannot exceed 4.50 to 1.00. The other material terms and conditions of the credit facility remain unchanged.

Senior Secured Notes. In April 2007, we amended our senior note agreement, effective as of March 30, 2007, to (i) provide that if our leverage ratio at the end of any fiscal quarter exceeds certain limitations, we will pay the holders of the note an excess leverage fee based on the daily average outstanding principal balance of the notes during such fiscal quarter multiplied by certain percentages set forth in the senior note agreement; (ii) increase the rate of interest on each note by 0.25% if, at any given time during an acquisition period (as defined in the senior note agreement), the leverage ratio exceeds 5.25 to 1.00; (iii) cause the leverage ratio to shift to a two-tiered structure if we or our subsidiaries incur unsecured note indebtedness; and (iv) limit our leverage ratio to 5.25 to 1.00 and our senior leverage ratio to 4.25 to 1.00 during periods where we have outstanding unsecured note indebtedness. The other material items and conditions of the senior note agreement remained unchanged.

We were in compliance with all debt covenants as of June 30, 2007 and expect to be in compliance with debt covenants for the next twelve months.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of June 30, 2007, is as follows:

	Payments Due by Period						
	Total	2007	2008	2009	2010	2011	Thereafter
				(In millions)			
Long-term debt	$1,133.8	$ 4.7	$ 9.4	$ 9.4	$20.3	$672.0	$ 418.0
Capital lease obligations	—	—	—	—	—	—	—
Operating leases	99.9	10.6	20.0	18.4	16.3	16.0	18.6
Unconditional purchase obligations	—	—	—	—	—	—	—
Other long-term obligations	—	—	—	—	—	—	—
Total contractual obligations	$1,233.7	$15.3	$29.4	$27.8	$36.6	$688.0	$ 436.6

The above table does not include any physical or financial purchase contract commitments for natural gas.

Recently issued Accounting Standards

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), *"Accounting for Uncertainty in Income Taxes"*. FIN 48 is an interpretation of FASB Statement No. 109, *"Accounting for Income Taxes"*. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken. The Partnership adopted FIN 48 effective January 1, 2007. There was no impact to the Partnership's financial statements as a result of FIN 48.

On September 13, 2006, the Securities Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (SAB 108), which establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the company's financial statements and the related disclosures. SAB 108 requires the use of a balance sheet and an income statement approach to evaluate whether either of these approaches results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. The Partnership adopted SAB 108 effective October 1, 2006 with no material impact on its financial statements.

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, "Fair Value Measurements" (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. While SFAS 157 does not add any new fair value measurements, it is intended to increase consistency and comparability of such measurement. The provisions of SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The adoption of this standard will not have a material impact on our results of operations, financial position or cash flows.

In February 2007, the FASB issued SFAS No. 159, "Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment to FASB Statement No. 115" (SFAS 159) permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact, if any, that the adoption of SFAS 159 will have on our financial statements.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended that are based on information currently available to management as well as management’s assumptions and beliefs. Statements included in this report which are not historical facts are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “forecast,” “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. Such statements reflect our current views with respect to future events based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to specific uncertainties discussed elsewhere in this Form 10-Q, the risk factors set forth in Part I, “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2006, and those set forth in Part II, “Item 1A. Risk Factors” of this report may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 3. ***Quantitative and Qualitative Disclosures about Market Risk***

Market risk is the risk of loss arising from adverse changes in market rates and prices. Our primary market risk is the risk related to changes in the prices of natural gas and NGLs. In addition, we are also exposed to the risk of changes in interest rates on our floating rate debt.

Interest Rate Risk

We are exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At June 30, 2007, our variable rate debt had a carrying value of $640.0 million which approximated its fair value, and our fixed rate debt had a carrying value of $493.8 million with an approximate fair value of $499.0 million. We attempt to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk. This is accomplished through a mix of bank debt with short-term variable rates and fixed rate senior and subordinated debt. In addition, we have entered into two separate interest rate swaps covering principal amounts of $50.0 million each under the credit facility for periods of three years each. The interest rate swaps reduce our risk by fixing the three month LIBOR rate over the term of the swap agreement.

In November 2006, we entered into an interest rate swap that fixed the three month LIBOR rate, prior to credit margin, at 4.95% on $50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. The fair value of the interest rate swap at June 30, 2007 was a $0.4 million asset.

In March 2007, we entered into an interest rate swap that fixed the three month LIBOR rate, prior to credit margin, at 4.875% on $50.0 million of related debt outstanding over the term of the swap agreement which expires on March 31, 2010. The fair value of the interest rate swap at June 30, 2007 was a $0.5 million asset.

The following table shows the carrying amount and fair value of long-term debt and the hypothetical change in fair value that would result from a 100-basis point change in interest rates. Unless otherwise noted, the hypothetical change in fair value could be a gain or a loss depending on whether interest rates increase or decrease.

	Carrying Amount	Fair Value(a)	Hypothetical Change in Fair Value
		(In millions)	
June 30, 2007	$1,133.8	$1,144.4	$ 10.6

(a) Fair value is based upon current market quotes and is the estimated amount required to purchase our long-term debt on the open market. This estimated value does not include any redemption premium.

Commodity Price Risk

Approximately 4.5% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices. As of June 30, 2007, we have hedged approximately 80% of our exposure to natural gas price fluctuations through December 2008. We also have hedges in place covering 80% of the liquid volumes we expect to receive at our south Louisiana assets through the first quarter of 2008; and 74% of the liquids at our other assets through the end of 2007 and 80% for the first quarter of 2008.

Another price risk we face is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. We enter each month with a balanced book of gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of gas bought or sold under either basis, which leaves us with short or long positions that must be covered. We use financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

We have commodity price risk associated with our processed volumes of natural gas. We currently process gas under four main types of contractual arrangements:

1. *Keep-whole contracts*: Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost (“shrink”) in processing. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. We control our risk on our current keep-whole contracts primarily through our ability to bypass processing when it is not profitable for us.

2. *Percent of proceeds contracts*: Under these contracts, we receive a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, our margins from these contracts are greater during periods of high liquids prices. Our margins from processing cannot become negative under percent of proceeds contracts, but do decline during periods of low NGL prices.

3. *Theoretical processing contracts*: Under these contracts, we stipulate with the producer the assumptions under which we will assume processing economics for settlement purposes, independent of actual processing results or whether the stream was actually processed. These contracts tend to have an inverse result to the keep-whole contracts, with better margins as processing economics worsen.

4. *Fee based contracts*: Under these contracts we have no commodity price exposure and are paid a fixed fee per unit of volume that is treated or conditioned.

Our primary commodity risk management objective is to reduce volatility in our cash flows. We maintain a Risk Management Committee, including members of senior management, which oversees all hedging activity. We enter into hedges for natural gas and NGLS using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our Risk Management Committee.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against unfavorable changes in such prices.

We manage our price risk related to future physical purchase or sale commitments for our producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas prices. However, we are subject to counterparty risk for both the physical and financial contracts. We account for certain of our commercial services natural gas marketing activities as energy trading contracts or derivatives. These energy-trading contracts are recorded at fair value with changes in fair value reported in earnings. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to our commercial services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period is reported as profit or loss on energy trading contracts in the statement of operations. In addition, realized gains and losses from settled contracts accounted for as cash flow hedges are recorded in Midstream revenue. As of June 30, 2007, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments had a net fair asset value of $3.1 million, excluding the fair value asset of less than $0.1 million associated with the NGL puts. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $6.4 million in the net fair value to a net liability of these contracts as of June 30, 2007 of $3.3 million. The value of the NGL puts would also decrease as a result of an increase in NGL prices, but we are unable to determine the impact of a 10% price change. Our maximum loss on these puts is the remaining fair value of the puts of less than $0.1 million.

Item 4. *Controls and Procedures*

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2007 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal controls over financial reporting that occurred in the three months ended June 30, 2007 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

PART II — OTHER INFORMATION

Item 1A. *Risk Factors*

Information about risk factors for the three months ended June 30, 2007 does not differ materially from that set forth in Part I, Item 1A, of our Annual Report on Form 10-K for the year ended December 31, 2006.

Item 6. *Exhibits*

The exhibits filed as part of this report are as follows (exhibits incorporated by reference are set forth with the name of the registrant, the type of report and registration number or last date of the period for which it was filed, and the exhibit number in such filing):

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779)
3.2	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our current report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007)
3.3	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779)
3.4	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004)

Number		Description
3.5	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779)
3.6	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779)
3.7	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779)
3.8	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779)
10.1	—	Third Amendment to Fourth Amended and Restated Credit Agreement, effective as of March 28, 2007, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007)
10.2	—	Letter Amendment No. 1 to Amended and Restated Note Purchase Agreement, effective as of March 28, 2007, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007)
31.1*	—	Certification of the principal executive officer
31.2*	—	Certification of the principal financial officer
32.1*	—	Certification of the principal executive officer and principal financial officer of the Company pursuant to 18 U.S.C. Section 1350

* Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, on the 9th day of August, 2007.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, L.P.,
its general partner

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ William W. Davis
William W. Davis
Executive Vice President and
Chief Financial Officer

EXHIBIT INDEX

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* Filed herewith.

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused the disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ BARRY E. DAVIS

Barry E. Davis,
President and Chief Executive Officer
(principal executive officer)

Date: August 9, 2007

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Crosstex Energy, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused the disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial data information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting.

/s/ WILLIAM W. DAVIS

William W. Davis,
Executive Vice President and Chief Financial Officer
(principal financial and accounting officer)

Date: August 9, 2007

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Crosstex Energy, L.P. (the "Registrant") on Form 10-Q for the quarter ended June 30, 2007 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Registrant.

/s/ BARRY E. DAVIS
Barry E. Davis
Chief Executive Officer

August 9, 2007

/s/ WILLIAM W. DAVIS
William W. Davis
Chief Financial Officer

August 9, 2007

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.