UNITED STATES
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 September 30, 2010

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐	Accelerated filer ☒
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

As of October 29, 2010, the Registrant had 50,206,111 common units outstanding.

TABLE OF CONTENTS

Table of Contents

CROSSTEX ENERGY, L.P.

Condensed Consolidated Balance Sheets

		September 30, 2010 (Unaudited)		December 31, 2009
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$	12,277	$	779
Accounts and notes receivable, net:				
Trade, accrued revenue and other		177,165		214,759
Fair value of derivative assets		5,610		9,112
Natural gas and natural gas liquids, prepaid expenses and other		11,841		14,692
Total current assets		206,893		239,342
Property and equipment, net of accumulated depreciation of $309,816 and $258,706, respectively		1,218,796		1,279,060
Fair value of derivative assets		2,269		5,665
Intangible assets, net of accumulated amortization of $141,971 and $115,813, respectively		508,739		534,897
Other assets, net		28,139		10,217
Total assets	$	1,964,836	$	2,069,181
LIABILITIES AND PARTNERS' EQUITY				
Current liabilities:				
Accounts payable, drafts payable, accrued gas purchases and other	$	152,930	$	179,709
Fair value of derivative liabilities		7,698		30,337
Current portion of long-term debt		7,058		28,602
Other current liabilities		54,393		51,014
Total current liabilities		222,079		289,662
Long-term debt		711,038		845,100
Other long-term liabilities		27,596		20,797
Deferred tax liability		7,858		8,234
Fair value of derivative liabilities		2,298		12,106
Commitments and contingencies		—		—
Partners' equity		993,967		893,282
Total liabilities and equity	$	1,964,836	$	2,069,181

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Condensed Consolidated Statements of Operations

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2010		2009		2010		2009
	(Unaudited) (In thousands, except per unit amounts)							
Revenues:								
Midstream	$	454,735	$	389,822	$	1,365,441	$	1,150,728
Operating costs and expenses:								
Purchased gas and NGLs		371,072		307,272		1,116,573		920,151
Operating expenses		26,476		29,027		78,365		84,733
General and administrative		11,277		16,051		35,669		43,616
Gain on sale of property		(588)		(356)		(14,367)		(899)
(Gain) loss on derivatives		1,582		(1,672)		6,872		(6,723)
Impairments		—		900		1,311		900
Depreciation and amortization		28,185		30,255		82,097		89,924
Total operating costs and expenses		438,004		381,477		1,306,520		1,131,702
Operating income		16,731		8,345		58,921		19,026
Other income (expense):								
Interest expense, net of interest income		(20,334)		(27,868)		(67,188)		(67,125)
Loss on extinguishment of debt		—		—		(14,713)		(4,669)
Other income		109		570		314		735
Total other income (expense)		(20,225)		(27,298)		(81,587)		(71,059)
Loss from continuing operations before non-controlling interest and income taxes		(3,494)		(18,953)		(22,666)		(52,033)
Income tax provision		(161)		(369)		(809)		(1,244)
Loss from continuing operations, net of tax		(3,655)		(19,322)		(23,475)		(53,277)
Income (loss) from discontinued operations, net of tax		—		(3,962)		—		4,378
Gain from sale of discontinued operations, net of tax		—		97,423		—		97,423

Net income (loss)	(3,655)	74,139	(23,475)	48,524
Less: Net income (loss) from continuing operations attributable to the non-controlling interest	13	(50)	(11)	(9)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (3,668)	$ 74,189	$ (23,464)	$ 48,533
Preferred interest in net income attributable to Crosstex Energy, L.P.	$ 3,676	$ —	$ 9,926	$ —
Beneficial conversion feature attributable to preferred units	$ —	$ —	$ 22,279	$ —
General partner interest in net income (loss)	$ (820)	$ 681	$ (3,596)	$ (1,210)
Limited partners' interest in net income (loss) attributable to Crosstex Energy, L.P.	$ (6,524)	$ 73,508	$ (52,073)	$ 49,743
Net income (loss) attributable to Crosstex Energy, L.P. per limited partners' unit:				
Basic common unit	$ (0.13)	$ 1.46	$ (1.02)	$ 0.32
Diluted common unit	$ (0.13)	$ 1.44	$ (1.02)	$ 0.31
Basic and diluted senior subordinated series D unit (see Note 5(c))	$ —	$ —	$ —	$ 8.85

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Nine Months Ended September 30, 2010

	Common Units		Preferred Units		General Partner Interest		Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units			
					(Unaudited) (In thousands)				
Balance, December 31, 2009	$ 873,858	49,163	$ —	—	$ 18,860	1,003	$ (2,670)	$ 3,234	$ 893,282
Issuance of preferred units	—		120,786	14,706	—	—	—	—	120,786
Beneficial conversion feature attributable to preferred units	(22,279)	—	22,279	—	—	—	—	—	—
Proceeds from exercise of unit options	667	152							667
Conversion of restricted units for common units, net of units withheld for taxes	(2,737)	876	—	—	—	—	—	—	(2,737)
Conversion of restricted units for common units, net of units withheld for Taxes (shares)									
Capital contributions	—	—	—	—	2,792	321	—	—	2,792
Stock-based compensation	3,962	—	—	—	3,144	—	—	—	7,106
Distributions	—	—	(6,250)	—	—	—	—	—	(6,250)
Net income (loss)	(29,794)	—	9,926	—	(3,596)	—	—	(11)	(23,475)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	1,637	—	1,637
Adjustment in fair value of derivatives	—	—	—	—	—	—	420	—	420
Distribution to non-controlling interest	—	—	—	—	—	—	—	(261)	(261)
Balance, September 30, 2010	$ 823,677	50,191	$ 146,741	14,706	$ 21,200	1,324	$ (613)	$ 2,962	$ 993,967

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(Unaudited) (In thousands)			
Net income (loss)	$ (3,655)	$ 74,139	$ (23,475)	$ 48,524
Hedging gains (losses) reclassified to earnings	(81)	171	1,637	(5,688)
Adjustment in fair value of derivatives	(601)	99	420	(1,165)
Comprehensive income (loss)	(4,337)	74,409	(21,418)	41,671
Comprehensive income (loss) attributable to non-controlling interest	13	(50)	(11)	(9)
Comprehensive income (loss) attributable to Crosstex Energy, L.P.	$ (4,350)	$ 74,459	$ (21,407)	$ 41,680

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Nine Months Ended September 30,	
	2010	2009
	(Unaudited) (In thousands)	

Cash flows from operating activities:		
Net income (loss)	$ (23,475)	$ 48,524
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	82,097	100,574
Gain on sale of property	(14,367)	(98,361)
Impairments	1,311	900
Deferred tax (benefit) expense	(375)	(543)
Non-cash stock-based compensation	7,106	6,276
Derivatives mark to market interest rate settlement	(24,160)	—
Non-cash derivatives (gain) loss	892	(3,021)
Non-cash loss on debt extinguishment	5,396	4,669
Accrual (payment) of interest paid-in-kind debt	(11,558)	6,042
Amortization of debt issue costs	5,213	7,654
Amortization of discount on notes	1,212	—
Changes in assets and liabilities:		
Accounts receivable, accrued revenue and other	37,508	168,187
Natural gas and natural gas liquids, prepaid expenses and other	476	(1,766)
Accounts payable, accrued gas purchases and other accrued liabilities	(20,967)	(176,440)
Net cash provided by operating activities	46,309	62,695
Cash flows from investing activities:		
Additions to property and equipment	(29,762)	(90,793)
Insurance recoveries on property and equipment	2,599	9,687
Proceeds from sale of property	60,053	245,276
Net cash provided by investing activities	32,890	164,170
Cash flows from financing activities:		
Proceeds from borrowings	990,912	489,943
Payments on borrowings	(1,138,205)	(673,470)
Proceeds from capital lease obligations	—	1,486
Payments on capital lease obligations	(1,671)	(1,867)
Decrease in drafts payable	(5,214)	(17,872)
Debt refinancing costs	(28,520)	(13,784)
Conversion of restricted units, net of units withheld for taxes	(2,737)	(134)
Distributions to non-controlling interest	(261)	(316)
Distribution to partners	(6,250)	(11,597)
Proceeds from issuance of preferred units	120,786	—
Proceeds from exercise of unit options	667	—
Contributions from general partner	2,792	15
Net cash used in financing activities	(67,701)	(227,596)
Net increase (decrease) in cash and cash equivalents	11,498	(731)
Cash and cash equivalents, beginning of period	779	1,636
Cash and cash equivalents, end of period	$ 12,277	$ 905
Cash paid for interest	$ 63,769	$ 69,015
Cash paid for income taxes	$ 1,533	$ 1,387

See accompanying notes to condensed consolidated financial statements.

Table of Contents

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements

September 30, 2010
(Unaudited)

(1) General

Unless the context requires otherwise, references to “we,” “us,” “our” orthe “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, 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 gather for a fee or purchase the gas production, processes natural gas for the removal of NGLs, transports natural gas and NGLs and ultimately provides natural gas and NGLs 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 markets 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. 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. Certain reclassifications have been made to the consolidated financial statements for the prior year to conform to the current presentation. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Partnership’s annual report on Form 10-K for the year ended December 31, 2009.

(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) Recent Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update (ASU) 2010-06, *Improving Disclosures about Fair Value Measurements*, which amends FASB ASC Topic 820, Fair Value Measurements and Disclosures. The ASU requires reporting entities to make new disclosures about recurring or nonrecurring fair-value measurements including significant transfers into and out of Level 1 and Level 2 fair-value measurements and information about purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair-value measurements. The ASU also clarifies existing fair-value measurement disclosure guidance about the level of disaggregation, inputs, and valuation techniques. The Partnership has evaluated the ASU but has determined that it is not currently impacted by the update.

(2) Asset Dispositions

The Partnership sold its Midstream assets in Alabama, Mississippi and south Texas for $217.6 million in August 2009. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $212.0 million were used to repay long-term indebtedness and the Partnership recognized a gain on sale of $97.2 million. In October 2009, the Partnership sold its Treating assets for net proceeds of $265.4 million. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $258.1 million were used to repay long-term indebtedness and the Partnership recognized a gain on sale of $86.3 million.

Table of Contents

The revenues, operating expenses, general and administrative expenses associated directly with the sold assets, depreciation and amortization expense, allocated Texas margin tax and an allocated interest expense related to the operations of the sold assets have been segregated from continuing operations and reported as discontinued operations for the three and nine months ended September 30, 2009. Interest expense of $10.6 million and $29.0 million for the three and nine months ended September 30, 2009, respectively, was allocated to discontinued operations related to the debt repaid from the proceeds from the asset dispositions using average historical interest rates. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are revenues and income from discontinued operations (in thousands):

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
Midstream revenues	$ 43,686	$ 327,211
Treating revenues	$ 13,917	$ 45,663
Income (loss) from discontinued operations, net of tax	$ (3,962)	$ 4,378
Gain from sales of discontinued operations, net of tax	$ 97,423	$ 97,423

(3) Long-Term Debt

As of September 30, 2010 and December 31, 2009, long-term debt consisted of the following (in thousands):

	September 30, 2010	December 31, 2009
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin; interest rate at December 31, 2009 was 6.75%	$ —	$ 529,614
New credit facility, interest based on Prime and/or LIBOR plus an applicable margin; interest rate at September 30, 2010 was 6.0%	—	—
Senior secured notes (including PIK notes (1) of $9.5 million), weighted average interest rate at December 31 2009 was 10.5%	—	326,034
Senior unsecured notes, net of discount of $13.9 million, which bears interest at the rate of 8.875%	711,038	
Series B secured note assumed in the Eunice transaction, which bears interest at the rate of 9.5%	7,058	18,054
	718,096	873,702
Less current portion	(7,058)	(28,602)
Debt classified as long-term	$ 711,038	$ 845,100

(1) The senior secured notes began accruing additional interest of 1.25% per annum in February 2009 in the form of an increase in the principal amounts thereof (the “PIK notes”). These notes were paid in full in February 2010.

New Credit Facility. In February 2010, the Partnership amended and restated its existing secured bank credit facility with a new syndicated secured bank credit facility (the “new credit facility”). The new credit facility has a borrowing capacity of $420.0 million and matures in February 2014. Net proceeds from the new credit facility along with net proceeds from the senior unsecured notes discussed under *“Senior Unsecured Notes”* below were used to, among other things, repay the Partnership’s credit facility and repay and retire all outstanding senior secured notes (including PIK notes) in February 2010. The Partnership recognized a loss on extinguishment of debt of $14.7 million when the debt was repaid due to make-whole interest payments on the senior secured debt of $9.3 million and the write-off of unamortized debt costs of $5.4 million. Debt refinancing costs totaling $28.1 million associated with new borrowings, including the senior unsecured notes, are included in other noncurrent assets as of September 30, 2010 and amortized to interest expense over the term of the related debt.

As of September 30, 2010, there were no borrowings under the new bank credit facility and $99.9 million in outstanding letters of credit, leaving approximately $320.1 million available for future borrowing.

Table of Contents

The new credit facility is guaranteed by substantially all of the Partnership’s subsidiaries and is secured by first priority liens on substantially all of the Partnership’s assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of its equity interests in substantially all of the Partnership's subsidiaries.

The Partnership may prepay all loans under the new credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The new credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, extraordinary receipts, equity issuances and debt incurrences, but these mandatory prepayments do not require any reduction of the lenders' commitments under the new credit facility.

Under the new credit facility, borrowings bear interest at the Partnership's option at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate) plus an applicable margin. The Partnership pays a per annum fee on all letters of credit issued under the new credit facility and a commitment fee of 0.50% per annum on the unused availability under the new credit facility. The letter of credit fee and the applicable margins for the interest rate vary quarterly based on the Partnership's leverage ratio (as defined in the new credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letter of Credit Fees
Greater than or equal to 5.00 to 1.00	3.25%	4.25%	4.25%
Greater than or equal to 4.50 to 1.00 and less than 5.00 to 1.00	3.00%	4.00%	4.00%
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	2.75%	3.75%	3.75%
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	2.50%	3.50%	3.50%
Less than 3.50 to 1.00	2.25%	3.25%	3.25%

Based on the forecasted leverage ratio for 2010, the Partnership expects the applicable margin for the interest rate and letter of credit fee to be at the mid-point of these ranges. The new credit facility does not have a floor for the Base Rate or the Eurodollar Rate.

The new credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter (except for the interest coverage ratio, which builds to a four-quarter test during 2010).

The maximum permitted leverage ratio is as follows:

· 5.50 to 1.00 for the fiscal quarter ending September 30, 2010;

· 5.25 to 1.00 for the fiscal quarter ending December 31, 2010;

· 5.00 to 1.00 for the fiscal quarter ending March 31, 2011;

· 4.75 to 1.00 for the fiscal quarter ending June 30, 2011; and

· 4.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

The maximum permitted senior leverage ratio (as defined in the new credit facility, but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges), is 2.50 to 1.00.

The minimum consolidated interest coverage ratio (as defined in the new credit facility, but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is as follows:

· 1.75 to 1.00 for the fiscal quarters ending September 30, 2010 through December 31, 2010;

· 2.00 to 1.00 for the fiscal quarter ending March 31, 2011;

· 2.25 to 1.00 for the fiscal quarter ending June 30, 2011; and

· 2.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

In addition, the new credit facility contains various covenants that, among other restrictions, limit the Partnership's ability to:

· grant or assume liens;

· make investments;

· incur or assume indebtedness;

· engage in mergers or acquisitions;

· sell, transfer, assign or convey assets;

· repurchase its equity, make distributions and certain other restricted payments;

· change the nature of its business;

· engage in transactions with affiliates;

· enter into certain burdensome agreements;

· make certain amendments to the omnibus agreement or its subsidiaries' organizational documents;

- prepay the senior unsecured notes and certain other indebtedness; and
- enter into certain hedging contracts.

The new credit facility permits the Partnership to make quarterly distributions to unitholders so long as no default exists under the new credit facility.

Each of the following is an event of default under the new credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation, or covenant in the new credit facility or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- the Partnership or any of its subsidiaries default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- certain ERISA events involving the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries; and
- a change in control (as defined in the new credit facility).

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under the new credit facility will immediately become due and payable. If any other event of default exists under the new credit facility, the lenders may accelerate the maturity of the obligations outstanding under the new credit facility and exercise other rights and remedies. In addition, if any event of default exists under the new credit facility, the lenders may commence foreclosure or other actions against the collateral.

If any default occurs under the new credit facility, or if the Partnership is unable to make any of the representations and warranties in the new credit facility, the Partnership will be unable to borrow funds or have letters of credit issued under the new credit facility.

The Partnership expects to be in compliance with the covenants in the new credit facility for at least the next twelve months.

Series B Secured Note. On October 20, 2009, the Partnership acquired the Eunice natural gas liquids processing plant and fractionation facility which includes an $18.1 million series B secured note. This note bears an interest rate of 9.5%. The remaining payment of $7.4 million including interest is due in 2011.

Senior Unsecured Notes. On February 10, 2010, the Partnership issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the “notes”) due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under its new credit facility discussed above, were used to repay in full amounts outstanding under its old bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with its existing credit facility. Interest payments are due semi-annually in arrears which commenced on August 15, 2010.

The indenture governing the notes contains covenants that, among other things, limit the Partnership’s ability and the ability of certain of its subsidiaries to:

- sell assets including equity interests in its subsidiaries;
- pay distributions on, redeem or repurchase units or redeem or repurchase its subordinated debt (as discussed in more detail below);
- make investments;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from its restricted subsidiaries to the Partnership;
- consolidate, merge or transfer all or substantially all of its assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; or
- engage in certain business activities.

The indenture provides that if the Partnership’s fixed charge coverage ratio (the ratio of its consolidated cash flow to its fixed charges, each as defined in the indenture) for the most recently ended four full fiscal quarters is not less than 2.0 to 1.0, the Partnership will be permitted to pay distributions to its unitholders in an amount equal to available cash from operating surplus (each as defined in the partnership agreement) with respect to the Partnership’s preceding fiscal quarter plus a number of items, including the net cash proceeds received by the Partnership as a capital contribution or from the issuance of equity interests since the date of the indenture, to the extent not previously expended. If the Partnership’s fixed charge coverage ratio is less than 2.0 to 1.0, the Partnership will be able to pay distributions to its unitholders in an amount equal to an $80.0 million basket (less amounts previously expended pursuant to such basket), plus the same number of items discussed in the preceding sentence to the extent not previously expended. The Partnership is in compliance with this ratio as of September 30, 2010.

If the notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, many of the covenants discussed above will terminate. The Partnership's current ratings on its bonds from Moody's Investors Service, Inc and Standard & Poor's Rating Services are B3 and B+, respectively.

The Partnership may redeem up to 35% of the notes at any time prior to February 15, 2013 with the cash proceeds from equity offerings at a redemption price of 108.875% of the principal amount of the notes (plus accrued and unpaid interest to the redemption date) provided that:

- at least 65% of the aggregate principal amount of the senior notes remains outstanding immediately after the occurrence of such redemption; and
- the redemption occurs within 120 days of the date of the closing of the equity offering.

Prior to February 15, 2014, the Partnership may redeem the notes, in whole or in part, at a "make-whole" redemption price. On or after February 15, 2014, the Partnership may redeem all or a part of the notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on February 15, 2014, 102.219% for the twelve-month

period beginning February 15, 2015 and 100.00% for the twelve-month period beginning on February 15, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the notes.

Each of the following is an event of default under the indenture:

- failure to pay any principal or interest when due;
- failure to observe any other agreement, obligation, or other covenant in the indenture, subject to the cure periods for certain failures;
- the Partnership or any of its subsidiaries' default under other indebtedness that exceeds a certain threshold amount;
- failures by it or any of its subsidiaries to pay final judgments that exceed a certain threshold amount; and
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries.

If an event of default relating to bankruptcy or other insolvency events occurs, the senior unsecured notes will immediately become due and payable. If any other event of default exists under the indenture, the trustee under the indenture or the holders of the senior unsecured notes may accelerate the maturity of the senior unsecured notes and exercise other rights and remedies.

The senior unsecured notes are jointly and severally guaranteed by each of the Partnership's current material subsidiaries (the "Guarantors"), with the exception of our regulated Louisiana subsidiaries - - Crosstex LIG, LLC and Crosstex Tuscaloosa, LLC, (which may only guarantee up to $500.0 million of the Partnership's debt), Crosstex DC Gathering, J.V. (our joint venture in Denton County, Texas is not 100% owned by the Partnership) and Crosstex Energy Finance Corporation (a wholly owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Partnership's indebtedness, including the senior unsecured notes). Since certain wholly owned subsidiaries do not guarantee the senior unsecured notes, the condensed consolidating financial statements of the guarantors and non-guarantors as of and for the three and nine months ended September 30, 2010 and 2009 are disclosed below in accordance with Rule 3-10 of Regulation S-X.

Condensed Consolidating Balance Sheets
September 30, 2010

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 190,661	$ 16,232	$ —	$ 206,893
Property, plant and equipment, net	988,917	229,879	—	1,218,796
Total other assets	539,144	3	—	539,147
Total assets	$ 1,718,722	$ 246,114	$ —	$ 1,964,836
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 216,000	$ 6,079	$ —	$ 222,079
Long-term debt	711,038	—	—	711,038
Other long-term liabilities	37,752	—	—	37,752
Partners' capital	753,932	240,035	—	993,967
Total liabilities & partners' capital	$ 1,718,722	$ 246,114	$ —	$ 1,964,836

December 31, 2009

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
ASSETS				
Total current assets	$ 226,583	$ 12,759	$ —	$ 239,342
Property, plant and equipment, net	1,045,991	233,069	—	1,279,060

	Guarantors	Non Guarantors	Elimination	Consolidated
Total other assets	550,776	3		550,779
Total assets	$ 1,823,350	$ 245,831	$ —	$ 2,069,181
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 283,539	$ 6,123	$ —	$ 289,662
Long-term debt	845,100	—	—	845,100
Other long-term liabilities	41,137	—	—	41,137
Partners' capital	653,574	239,708	—	893,282
Total liabilities & partners' capital	$ 1,823,350	$ 245,831	$ —	$ 2,069,181

Condensed Consolidating Statements of Operations
For the Three Months Ended September 30, 2010

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 439,264	$ 20,765	$ (5,294)	$ 454,735
Total operating costs and expenses	(434,949)	(8,349)	5,294	(438,004)
Operating income (loss)	4,315	12,416	—	16,731
Interest expense, net	(20,334)	—	—	(20,334)
Other income (loss)	109	—	—	109
Income from continuing operations before non-controlling interest and income taxes	(15,910)	12,416	—	(3,494)
Income tax provision	(159)	(2)	—	(161)
Net income attributable to non-controlling interest	—	(13)	—	(13)
Net income (loss) attributable to Crosstex Energy, L.P.	$ (16,069)	$ 12,401	$ —	$ (3,668)

For the Three Months Ended September 30, 2009

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 378,675	$ 23,372	$ (12,225)	$ 389,822
Total operating costs and expenses	(386,063)	(7,639)	12,225	(381,477)
Operating income (loss)	(7,388)	15,733	—	8,345
Interest expense, net	(27,867)	(1)	—	(27,868)
Other income	570	—	—	570
Income from continuing operations before non-controlling interest and income taxes	(34,685)	15,732	—	(18,953)
Income tax provision	(357)	(12)	—	(369)
Income from discontinued operations, net of tax	93,461	—	—	93,461
Net loss attributable to non-controlling interest	—	50	—	50
Net income (loss) attributable to Crosstex Energy, L.P.	$ 58,419	$ 15,770	$ —	$ 74,189

Table of Contents

For the Nine Months Ended September 30, 2010

	Guarantors	Non Guarantors	Elimination	Consolidated
		(In thousands)		
Total revenues	$ 1,321,810	$ 62,930	$ (19,299)	$ 1,365,441
Total operating costs and expenses	(1,299,802)	(26,017)	19,299	(1,306,520)
Operating income (loss)	22,008	36,913	—	58,921
Interest expense, net	(67,182)	(6)	—	(67,188)
Other expense	(14,399)	—	—	(14,399)
Income from continuing operations before non-controlling interest and income taxes	(59,573)	36,907	—	(22,666)
Income tax provision	(801)	(8)	—	(809)
Net loss attributable to non-controlling interest	—	11	—	11
Net income (loss) attributable to Crosstex Energy, L.P.	$ (60,374)	$ 36,910	$ —	$ (23,464)

For the Nine Months Ended September 30, 2009

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,123,080	$ 54,277	$ (26,629)	$ 1,150,728
Total operating costs and expenses	(1,134,365)	(23,966)	26,629	(1,131,702)
Operating income (loss)	(11,285)	30,311	—	19,026
Interest expense, net	(67,122)	(3)	—	(67,125)
Other expense	(3,934)	—	—	(3,934)
Income from continuing operations before non-controlling interest and income taxes	(82,341)	30,308	—	(52,033)
Income tax provision	(1,231)	(13)	—	(1,244)

Income from discontinued operations, net of tax		101,801		—		—		101,801
Net loss attributable to non-controlling interest		—		9		—		9
Net income (loss) attributable to Crosstex Energy, L.P.	$	18,229	$	30,304	$	—	$	48,533

Condensed Consolidating Statements of Cash Flow
For the Nine Months Ended September 30, 2010

	Guarantors		Non Guarantors		Elimination		Consolidated	
			(In thousands)					
Net cash flows provided by operating activities	$	2,965	$	43,344	$	—	$	46,309
Net cash flows provided by (used in) investing activities	$	39,924	$	(7,034)	$	—	$	32,890
Net cash flows provided by (used in) financing activities	$	(67,441)	$	(36,571)	$	36,311	$	(67,701)

Table of Contents

For the Nine Months Ended September 30, 2009

	Guarantors		Non Guarantors		Elimination		Consolidated	
			(In thousands)					
Net cash flows provided by operating activities	$	28,743	$	33,952	$	—	$	62,695
Net cash flows provided by (used in) investing activities	$	174,737	$	(10,567)	$	—	$	164,170
Net cash flows provided by (used in) financing activities	$	(227,279)	$	(23,192)	$	22,875	$	(227,596)

(4) Obligations Under Capital Lease

The Partnership entered into 9 and 10-year capital leases for certain equipment. Assets under capital leases as of September 30, 2010 are summarized as follows (in thousands):

Equipment	$	37,199
Less: Accumulated amortization		(6,086)
Net assets under capital lease	$	31,113

The following are the minimum lease payments to be made in the following years indicated for the capital leases in effect as of September 30, 2010 (in thousands):

2010	$	1,146
2011 through 2014 ($4,582 annually)		18,329
Thereafter		21,262
Less: Interest		(8,691)
Net minimum lease payments under capital lease		32,046
Less: Current portion of net minimum lease payments		(4,450)
Long-term portion of net minimum lease payments	$	27,596

(5) Partners' Capital

(a) Sale of Preferred Units

On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions for net proceeds of $120.8 million. Crosstex Energy, GP, L.P. made a general partner contribution of $2.6 million in connection with the issuance to maintain its 2% general partner interest. The 14,705,882 preferred units are convertible by the holders thereof at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. The Partnership has the right to force conversion of the preferred units after three years if (i) the daily volume-weighted average trading price of the common units is greater than $12.75 per unit for 20 out of the trailing 30 trading days ending on two trading days before the date on which the Partnership delivers notice of such conversion, and (ii) the average daily trading volume of common units must have exceeded 250,000 common units for 20 out of the trailing 30 trading days ending on two trading days before the date on which the Partnership delivers notice of such conversion. The preferred units are not redeemable but will pay a quarterly distribution that will be the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if the Partnership pays cash distribution on common units.

Table of Contents

The preferred units were issued at a discount to the market price of the common units they are convertible into. This discount totaling $22.3 million represents a beneficial conversion feature (BCF) and is reflected as a reduction in common unit equity and an increase in preferred equity to reflect the market value of the preferred units at issuance on the Partnership's consolidated statement of changes in partners' equity for the nine months ended September 30, 2010. The impact of the BCF is also included in earnings per unit for the nine months ended September 30, 2010.

(b) Cash Distributions

Unless restricted by the terms of the Partnership's credit facility and/or senior unsecured note indenture, 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. As described under (a) Sale of Preferred Units above, the preferred units are entitled to a quarterly distribution equal to the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. The general partner is not entitled to a 2% distribution with respect to the quarterly preferred distribution of $0.2125 per unit that is made solely to the preferred unitholders. The general partner is entitled to a 2% distribution with respect to all distributions made to common unitholders. If the distributions are in excess of $0.2125 per unit, distributions are made 98% to the common and preferred unitholders and 2% to the general partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. Under the quarterly incentive distribution provisions, generally the Partnership's general partner is entitled to 13% of amounts the Partnership distributes in excess of $0.25 per unit, 23% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48% of amounts the Partnership distributes distribute in excess of $0.375 per unit. No incentive distributions were earned by the Partnership's general partner for the three and nine months ended September 30, 2010 and 2009. The first and second quarterly preferred unit distributions of $3.1 million ($0.2125 per unit for each quarter) were paid in cash in May 2010 and August 2010. In October 2010, the Partnership declared a third quarter distribution for its common and preferred units of $0.25 per unit to be paid in cash in November 2010.

(c) Earnings per Unit and Dilution Computations

The Partnership had common units and preferred units outstanding during the three and nine months ended September 30, 2010 and common units and senior subordinated series D units outstanding during the nine months ended September 30, 2009. The senior subordinated series D units, which converted to common units in March 2009, were considered common securities prior to conversion but were presented as a separate class of common equity because they did not participate in cash distributions during their subordination period. The senior subordinated series D units were issued in March 2007 at a discount, referred to as BCF, totaling $34.3 million to the market price of the common units they were convertible into at the end of their subordination period. Since the conversion of the senior subordinated series D units into common units was contingent (as described with the terms of such units) until the end of their subordination period, the BCF was not recognized until the end of such subordination period when the criteria for conversion was met. The BCFs attributable to both the senior subordinated series D units and the preferred units, discussed under *(a) Sale of Preferred Units* above, represent non-cash distributions that are treated in the same way as a cash distribution for earnings per unit computations.

The preferred units are entitled to a quarterly distribution equal to the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Income is allocated to the preferred units in an amount equal to the quarterly distribution with respect to the period earned.

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

Table of Contents

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Limited partners' interest in net income (loss)	$ (6,524)	$ 73,508	$ (52,073)	$ 49,743
Distributed earnings allocated to:				
Common units	$ —	$ —	$ —	$ 11,234
Unvested restricted units	—	—	—	134
Senior subordinated series D units (1)	—	—	—	34,297
Total distributed earnings	$ —	$ —	$ —	$ 45,665
Undistributed income (loss) allocated to:				
Common units	$ (6,394)	$ 71,431	$ (50,794)	$ 4,026
Unvested restricted units	(130)	2,077	(1,279)	52
Total undistributed loss	$ (6,524)	$ 73,508	$ (52,073)	$ 4,078
Net income (loss) allocated to:				
Common units	$ (6,394)	$ 71,431	$ (50,794)	$ 15,260
Unvested restricted units	(130)	2,077	(1,279)	186
Senior subordinated series D units	—	—	—	34,297
Total limited partners' interest in net loss	$ (6,524)	$ 73,508	$ (52,073)	$ 49,743
Limited partners' interest in income from discontinued operations:				
Common units	$ —	$ 89,004	$ —	$ 97,717
Unvested restricted units	—	2,588	—	2,047
Total income from discontinued operations (2)	$ —	$ 91,592	$ —	$ 99,764
Basic and diluted net income (loss) per unit from continuing operations:				
Common unit	$ (0.13)	$ (0.36)	$ (1.02)	$ (1.72)
Senior subordinated series D unit	$ —	$ —	$ —	$ 8.85
Basic and diluted net income on discontinued operations:				
Basic common unit	$ —	$ 1.81	$ —	$ 2.04
Diluted common units		1.79		1.98
Total basic and diluted net income (loss) per unit:				
Basic common unit	$ (0.13)	$ 1.46	$ (1.02)	$ 0.32
Diluted common units		1.44		0.31
Senior subordinated series D unit	$ —	$ —	$ —	$ 8.85

(1) Represents BCF recognized at end of subordination period for senior subordinated series D units.
(2) Represents 98.0% for the limited partners' interest in discontinued operations.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2010 and 2009 (in thousands):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Basic and diluted weighted average units outstanding:				
Weighted average limited partner common units outstanding	50,142	49,077	49,872	47,825
Diluted earnings per unit:				

Weighted average limited partner units outstanding	50,142	49,077	49,872	47,825
Dilutive effect of restricted units issued	—	671	—	303
Dilutive effect of senior subordinated units	—	—	—	1,164
Dilutive effect of exercise of options outstanding	—	4	—	—
Diluted weighted average limited partner common units outstanding	50,142	49,752	49,872	49,292
Weighted average diluted senior subordinated series D units outstanding	—	—	—	3,875

Table of Contents

All common unit equivalents were antidilutive in the three and nine months ended September 30, 2010 because the limited partners were allocated a net income loss in these periods.

When quarterly distributions are made pro-rata to common and preferred unitholders, net income for the general partner consists of incentive distributions to the extent earned, a deduction for stock-based compensation attributable to CEI's stock options and restricted shares and 2% of the original Partnership's net income (loss) adjusted for the CEI stock-based compensation specifically allocated to the general partner. When quarterly distributions are made solely to the preferred unitholders, the net income for the general partner consists of the CEI stock-based compensation deduction and 2% of the Partnership's net income (loss) after the allocation of income to the preferred unitholders with respect to their preferred distribution adjusted for the CEI stock-based compensation specifically allocated to the general partner. The net income (loss) allocated to the general partner is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Income allocation for incentive distributions	$ —	$ —	$ —	$ —
Stock-based compensation attributable to CEI's stock options and restricted shares	(762)	(819)	(3,063)	(2,225)
2% general partner interest in net income (loss)	(58)	1,500	(533)	1,015
General partner share of net income (loss)	$ (820)	$ 681	$ (3,596)	$ (1,210)

(6) Employee Incentive Plans

(a) Long-Term Incentive Plans

The Partnership accounts for share-based compensation in accordance with FASB ASC 718, which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements.

The Partnership and CEI each have similar unit or share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plan 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Cost of share-based compensation charged to general and administrative expense	$ 1,629	$ 1,883	$ 6,011	$ 5,037
Cost of share-based compensation charged to operating expense	231	471	1,095	1,239
Total amount charged to income	$ 1,860	$ 2,354	$ 7,106	$ 6,276

(b) 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 nine months ended September 30, 2010 is provided below:

Table of Contents

	Nine Months Ended September 30, 2010	
Crosstex Energy, L.P. Restricted Units:	**Number of Units**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	2,088,005	$ 7.31
Granted	214,685	10.31
Vested*	(1,163,537)	4.72
Forfeited	(56,319)	9.98
Non-vested, end of period	1,082,834	$ 10.37
Aggregate intrinsic value, end of period (in thousands)	$ 13,741	

* Vested units include 287,410 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued performance-based restricted units in 2008 to executive officers. The minimum level of performance-based awards is included in restricted units outstanding and is included in the current share-based compensation cost calculations at September 30, 2010. The achievement of greater than the minimum performance targets in the current business environment is less than probable. All performance-based awards are subject to reevaluation and adjustment until the restricted units vest in March 2011.

A summary of the restricted units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the three and nine months ended September 30, 2010 and 2009 are provided below (in thousands):

Crosstex Energy, L.P. Restricted Units:	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Aggregate intrinsic value of units vested	$ 3,735	$ 253	$ 10,835	$ 725
Fair value of units vested	$ 2,643	$ 547	$ 5,497	$ 3,439

As of September 30, 2010, 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 2.1 years.

(c) Unit Options

A summary of the unit option activity for the nine months ended September 30, 2010 is provided below:

Crosstex Energy, L.P. Unit Options:	Nine Months Ended September 30, 2010 Number of Units	Nine Months Ended September 30, 2010 Weighted Average Exercise Price
Outstanding, beginning of period	882,836	$ 6.43
Exercised	(150,632)	4.54
Forfeited	(55,714)	9.56
Expired	(5,617)	5.37
Outstanding, end of period	670,873	$ 6.61
Options exercisable at end of period	331,953	
Weighted average contractual term (years) end of period:		
Options outstanding	8.4	
Options exercisable	7.8	
Aggregate intrinsic value end of period (in thousands):		
Options outstanding	$ 4,859	
Options exercisable	$ 2,496	

A summary of the unit options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value of units vested (value per Black-Scholes option pricing model at date of grant) during the three and nine months ended September 30, 2010 and 2009 are provided below (in thousands):

Crosstex Energy, L.P. Unit Options:	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Intrinsic value of unit options exercised	$ 727	$ —	$ 1,016	$ —
Fair value of units vested	$ 469	$ 91	$ 762	$ 2,621

As of September 30, 2010, there was $0.8 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted average period of 1.9 years.

(d) Crosstex Energy, Inc.'s Restricted Stock

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 nine months ended September 30, 2010 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Nine Months Ended September 30, 2010 Number of Shares	Nine Months Ended September 30, 2010 Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	1,391,973	$ 9.37
Granted	288,104	6.82
Vested*	(477,266)	9.03
Forfeited	(57,044)	8.77
Non-vested, end of period	1,145,767	$ 8.71
Aggregate intrinsic value, end of period (in thousands)	$ 9,052	

* Vested shares include 108,223 shares withheld for payroll taxes paid on behalf of employees.

The Company issued performance-based restricted shares in 2008 to executive officers. The minimum level of performance-based awards is included in restricted shares outstanding and is included in the current share-based compensation cost calculations at September 30, 2010. The achievement of greater than the minimum performance targets in the current business environment is less than probable. All performance-based awards are subject to reevaluation and adjustment until the restricted shares vest in March 2011.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value of shares vested (market value at date of grant) during the three and nine months ended September 30, 2010 and 2009 are provided below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Crosstex Energy, Inc. Restricted Shares:	**2010**	**2009**	**2010**	**2009**
Aggregate intrinsic value of shares vested	$ 2,330	$ 107	$ 3,143	$ 831
Fair value of shares vested	$ 2,972	$ 371	$ 4,309	$ 3,640

As of September 30, 2010, there was $4.8 million of unrecognized compensation costs related to non-vested CEI restricted shares for officers and employees. The cost is expected to be recognized over a weighted average period of 2.0 years.

Table of Contents

(e) Crosstex Energy, Inc.'s Stock Options

CEI stock options have not been granted to officers or employees of the Partnership since 2005. The 30,000 CEI stock options previously awarded, vested and outstanding at December 31, 2009 that were held by officers and employees of the Partnership were forfeited on January 1, 2010.

***(7)* Derivatives**

Interest Rate Swaps

In conjunction with the repayment of its old credit facility in February 2010, the Partnership settled all of its interest rate swaps for total payments of $27.2 million. The balance of $0.6 million in accumulated other comprehensive income related to the interest rate swaps was recorded as realized loss as a part of the settlement. The Partnership did not enter into any new interest rate swaps during the nine months ended September 30, 2010.

The impact of the interest rate swaps on net income is included in other income (expense) in the consolidated statements of operations as part of interest expense, net, as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Change in fair value of derivatives that do not qualify for hedge accounting	$ —	$ (948)	$ 22,405	$ 2,470
Realized losses on derivatives	—	(4,914)	(26,542)	(14,130)
	$ —	$ (5,862)	$ (4,137)	$ (11,660)

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 price and location risks 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 accounting 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 swap 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 the Partnership's systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge fractionation spread risk at the Partnership's processing plants relating to the option to process versus bypassing the Partnership's equity gas.

The components of (gain) loss on derivatives in the consolidated statements of operations relating to commodity swaps are (in thousands):

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Change in fair value of derivatives that do not qualify for hedge accounting	$ 1,473	$ (1,126)	$ 958	$ (662)
Realized (gains) losses on derivatives	109	29	5,975	(6,311)
Ineffective portion of derivatives qualifying for hedge accounting	—	(11)	(61)	(14)
Net (gains) losses related to commodity swaps	$ 1,582	$ (1,108)	$ 6,872	$ (6,987)
Net (gains) losses included in income from discontinued operations	—	(564)	—	264
(Gains) losses on derivatives included in continuing operations	$ 1,582	$ (1,672)	$ 6,872	$ (6,723)

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

	September 30, 2010	December 31, 2009
Fair value of derivative assets — current, designated	$ 88	$ 369
Fair value of derivative assets — current, non-designated	5,522	8,743
Fair value of derivative assets — long term, designated	16	—
Fair value of derivative assets — long term, non-designated	2,253	5,665
Fair value of derivative liabilities — current, designated	(681)	(2,536)
Fair value of derivative liabilities — current, non-designated	(7,017)	(9,841)
Fair value of derivative liabilities — long term, designated	(41)	—
Fair value of derivative liabilities — long term, non-designated	(2,257)	(5,338)
Net fair value of derivatives	$ (2,117)	$ (2,938)

Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets at September 30, 2010 (all gas volumes are expressed in MMBtu's and liquids volumes are expressed in gallons). The remaining term of the contracts extend no later than December 2011 for derivatives, except for certain basis swaps that extend to March 2012. Changes in the fair value of the Partnership's mark to market derivatives 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. The ineffective portion is recorded in earnings immediately.

September 30, 2010

Transaction Type	Volume	Fair Value
	(In thousands)	
Cash Flow Hedges:		
Liquids swaps (short contracts)	(5,818)	$ (679)
Liquids swaps (long contracts)	255	61
Total swaps designated as cash flow hedges		$ (618)
Mark to Market Derivatives:		
Swing swaps (short contracts)	(3,546)	$ (6)
Physical offsets to swing swap transactions (long contracts)	3,546	—
Basis swaps (long contracts)	32,120	5,757
Physical offsets to basis swap transactions (short contracts)	(535)	1,647
Basis swaps (short contracts)	(28,160)	(5,344)
Physical offsets to basis swap transactions (long contracts)	535	(1,947)
Third-party on-system swaps (long contracts)	230	(72)
Physical offsets to third-party on-system swap transactions (short contracts)	(230)	109
Processing margin hedges — liquids (short contracts)	(5,765)	(640)
Processing margin hedges — gas (long contracts)	665	(1,195)
Storage swap transactions (short contracts)	(80)	192
Total mark to market derivatives		$ (1,499)

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. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss as of September 30, 2010 of $9.5 million would be reduced to $3.3 million due to the netting feature, all of which relates to other energy companies.

Impact of Cash Flow Hedges

The impact of realized gains or losses from derivatives designated as cash flow hedge contracts in the consolidated statements of operations is summarized below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Increase (decrease) in Midstream revenue	**2010**	**2009**	**2010**	**2009**
Natural gas	$ —	$ 605	$ —	$ 1,762
Liquids	(13)	1,155	(1,123)	8,921
Realized gains included in income from discontinued operations	—	(187)	—	(852)
Realized gain (loss) included in income from continuing operations	$ (13)	$ 1,573	$ (1,123)	$ 9,831

Natural Gas

As of September 30, 2010, the Partnership has no balances in accumulated other comprehensive income related to natural gas.

Liquids

As of September 30, 2010, an unrealized derivative fair value net loss of $0.5 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this net amount, an approximate loss of $0.5 million is expected to be reclassified into earnings through September 2011. 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.

Table of Contents

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, 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 actively quoted prices. 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
September 30, 2010.	$ (1,495)	$ (4)	$ —	$ (1,499)

(8) Fair Value Measurements

FASB ASC 820 sets forth a framework for measuring fair value and required disclosures about fair value measurements of assets and liabilities. Fair value under FASB ASC 820 is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

FASB ASC 820 established a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Partnership's derivative contracts primarily consist of commodity swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined using discounted cash flow techniques. The techniques incorporate Level 1 and Level 2 inputs for future commodity prices that are readily available in public markets or can be derived from information available in publicly quoted markets. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in hierarchy.

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in thousands):

	September 30, 2010 Level 2	December 31, 2009 Level 2
Interest Rate Swaps	$ —	$ (24,728)
Commodity Swaps*	(2,117)	(2,938)
Total	$ (2,117)	$ (27,666)

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income at each measurement date.

(9) Fair Value of Financial Instruments

The estimated fair value of the Partnership's financial instruments has been determined by the Partnership using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount the Partnership could realize upon the sale or refinancing of such financial instruments (in thousands).

Table of Contents

	September 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 12,277	$ 12,277	$ 779	$ 779
Trade accounts receivable and accrued revenues	174,279	174,279	207,655	207,655
Fair value of derivative assets	7,879	7,879	14,777	14,777
Accounts payable, drafts payable and accrued gas purchases	150,882	150,882	174,007	174,007
Long-term debt	718,096	764,683	873,702	872,340
Obligations under capital lease	32,046	29,443	23,799	22,399
Fair value of derivative liabilities	9,996	9,996	42,443	42,443

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities.

The Partnership had no borrowings under its revolving credit facility included in long-term debt as of September 30, 2010 and had $529.6 million as of December 31, 2009 and accrued interest under floating interest rate structures. Accordingly, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the new and old credit facilities. As of September 30, 2010, the Partnership also had borrowings totaling $711.0 million under senior unsecured notes with a fixed rate of 8.875% and a series B secured note with a principal amount of $7.1 million with a fixed rate of 9.5%. As of December 31, 2009, the Partnership also had borrowings totaling $326.0 million under senior secured notes with a weighted average interest rate of 10.5% and the series B secured note with a principal amount of $18.1 million with a fixed rate of 9.5%. The fair value of the senior unsecured notes as of September 30, 2010 was based on third party market quotations. The fair values of the senior secured notes as of December 31, 2009 and the series B secured note as of September 30, 2010 and December 31, 2009 were adjusted to reflect current market interest rates for such borrowings on the applicable date. The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction adjusted for credit risk of the Partnership and/or the counterparty as required under FASB ASC 820.

(10) Commitments and Contingencies

(a) Employment Agreements

Certain members of management of the Partnership are parties to employment contracts with the general partner. The employment agreements provide those senior managers 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 acquired LIG Pipeline Company and its subsidiaries on April 1, 2004. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. The seller, AEP, has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third-party company pursuant to which the remediation costs associated with these sites have been assumed by this third party company that specializes in remediation work. The Partnership does not expect to incur any material liability with these sites; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations. In addition, the Partnership has disclosed possible Clean Air Act monitoring deficiencies it has discovered to the Louisiana Department of Environmental Quality (LDEQ) and is working with the department to correct these deficiencies and to address modifications to facilities to bring them into compliance. The Partnership does not expect to incur any material environmental liability associated with these issues.

(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.

In December 2008, Denbury Onshore, LLC ("Denbury") initiated formal arbitration proceedings against Crosstex CCNG Processing Ltd., Crosstex Energy Services, L.P., Crosstex North Texas Gathering, L.P. and Crosstex Gulf Coast Marketing Ltd., all wholly-owned subsidiaries of the Partnership, asserting a claim for breach of contract under a gas processing agreement. Denbury alleged damages in the amount of $16.2 million, plus interest and attorneys' fees. Crosstex denied any liability and sought to have the action dismissed. An arbitration hearing was held in December 2009 and in February 2010 Denbury was awarded $3.0 million plus interest, attorneys' fees and costs for its claims. The final award totaling $3.5 million was paid in May 2010. The Partnership accrued an estimate of $3.7 million for this award as of December 31, 2009 and reflected the related expense in purchased gas costs in the fourth quarter of 2009.

On June 7, 2010, Formosa Plastics Corporation, Texas, Formosa Plastics Corporation, America, Formosa Utility Venture, Ltd., and Nan Ya Plastics Corporation, America filed a lawsuit against Crosstex Energy, Inc., Crosstex Energy, L.P., Crosstex Energy GP, L.P., Crosstex Energy GP, LLC, Crosstex Energy Services, L.P., and Crosstex Gulf Coast Marketing, Ltd. in the 24th Judicial District Court of Calhoun County, Texas, asserting claims for negligence, *res ipsa loquitor*, products liability and strict liability relating to the alleged receipt by the plaintiffs of natural gas liquids into their facilities from facilities operated by the Partnership. The lawsuit alleges that the plaintiffs have incurred at least $65.0 million in damages, including damage to equipment and lost profits. The Partnership has submitted the claim to its insurance carriers and intends to vigorously defend the lawsuit. The Partnership believes that any recovery would be within applicable policy limits. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

At times, the Partnership's gas-utility subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain provided under state law. As a result, the Partnership (or its subsidiaries) is a party to a number of lawsuits under which a court will determine the value of pipeline easements or other property interests obtained by the Partnership's gas utility subsidiaries by condemnation. Damage awards in these suits should reflect the value of the property interest acquired and the diminution in the value of the remaining property owned by the landowner. However, some landowners have alleged unique damage theories to inflate their damage claims or assert valuation methodologies that could result in damage awards in excess of the amounts anticipated. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not expect that awards in these matters will have a material adverse impact on its consolidated results of operations or financial condition.

On October 23, 2006, Crosstex North Texas Gathering, L.P. filed a lawsuit against Robert L. Dow in the County Court at Law No. 1 of Tarrant County, Texas seeking a pipeline easement across a portion of the defendant's sand and gravel mining operation. The court awarded the defendant $0.1 million in damages, but the defendant appealed and claimed damages for the taking damages to the remainder of his property of $50.0 million and damages due to lost profits from the sale of frac sand of $90.0 million. On October 8, 2010, the Partnership settled this matter and received a pipeline easement in exchange for a payment of $6.75 million. This settlement was accrued in current liabilities as of September 30, 2010 and included as a property cost.

The Partnership (or its subsidiaries) is defending a number of lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering and processing facilities in urban and occupied rural areas. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

(11) Segment Information

In 2010, the Partnership's management realigned the composition of its segments. Accordingly, the Partnership has recast its segment information for prior periods to reflect this new alignment.

Identification of operating segments is based principally upon regions served. The Partnership's reportable segments consist of the natural gas gathering, processing and transmission operations located in north Texas (NTX), the pipelines and processing plants located in Louisiana (LIG) and the south Louisiana processing and NGL assets, including gas and NGL marketing activities (PNGL). Operating activity for assets sold in the comparative periods that was not considered discontinued operations as well as intersegment eliminations is shown in the corporate segment. Segment data for the periods ended September 30, 2009 do not include assets held for sale.

Table of Contents

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

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. Profit in the corporate segment for the three and nine months ended September 30, 2009 includes the operating activity of assets sold but not considered discontinued operations.

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

	LIG	NTX	PNGL	Corporate	Totals
			(In thousands)		
Three Months Ended September 30, 2010:					
Sales to external customers	$ 232,220	$ 85,510	$ 137,005	$ —	$ 454,735
Sales to affiliates	18,228	20,516	—	(38,744)	—
Purchased gas and NGLs	(221,624)	(66,207)	(121,985)	38,744	(371,072)
Operating expenses	(7,877)	(11,525)	(7,074)	—	(26,476)
Segment profit	$ 20,947	$ 28,294	$ 7,946	$ —	$ 57,187
Gain (loss) on derivatives	$ (1,561)	$ (70)	$ 49	$ —	$ (1,582)
Depreciation, amortization and impairments	$ (3,114)	$ (15,896)	$ (8,058)	$ (1,117)	$ (28,185)
Capital expenditures	$ 3,006	$ 14,635	$ 1,389	$ 810	$ 19,840
Identifiable assets	$ 327,418	$ 1,111,274	$ 473,668	$ 52,476	$ 1,964,836
Three Months Ended September 30, 2009:					
Sales to external customers	$ 199,926	$ 101,600	$ 84,146	$ 4,150	$ 389,822
Sales to affiliates	15,662	18,993	—	(34,655)	—
Purchased gas and NGLs	(187,174)	(79,916)	(72,221)	32,039	(307,272)
Operating expenses	(7,232)	(12,639)	(8,606)	(550)	(29,027)
Segment profit	$ 21,182	$ 28,038	$ 3,319	$ 984	$ 53,523
Gain (loss) on derivatives	$ 734	$ 1,021	$ (83)	$ —	$ 1,672
Depreciation, amortization and impairments	$ (3,179)	$ (17,088)	$ (9,039)	$ (1,849)	$ (31,155)
Capital expenditures	$ 7,404	$ 4,193	$ —	$ 70	$ 11,667
Identifiable assets	$ 336,911	$ 1,180,796	$ 438,052	$ 58,170	$ 2,013,929
Nine Months Ended September 30, 2010:					
Sales to external customers	$ 677,750	$ 236,517	$ 451,174	$ —	$ 1,365,441
Sales to affiliates	62,201	66,106	6	(128,313)	—
Purchased gas and NGLs	(653,515)	(184,370)	(407,001)	128,313	(1,116,573)
Operating expenses	(24,140)	(34,793)	(19,432)	—	(78,365)
Segment profit	$ 62,296	$ 83,460	$ 24,747	$ —	$ 170,503
Gain (loss) on derivatives	$ (2,465)	$ (4,577)	$ 170	$ —	$ (6,872)
Depreciation, amortization and impairments	$ (9,186)	$ (47,000)	$ (23,886)	$ (3,336)	$ (83,408)
Capital expenditures	$ 8,908	$ 20,015	$ 2,309	$ 1,491	$ 32,723
Identifiable assets	$ 327,418	$ 1,111,274	$ 473,668	$ 52,476	$ 1,964,836
Nine Months Ended September 30, 2009:					
Sales to external customers	$ 615,860	$ 327,874	$ 195,417	$ 11,577	$ 1,150,728
Sales to affiliates	44,084	48,889	—	(92,973)	—
Purchased gas and NGLs	(589,942)	(253,940)	(162,009)	85,740	(920,151)
Operating expenses	(19,846)	(37,910)	(24,871)	(2,106)	(84,733)
Segment profit	$ 50,156	$ 84,913	$ 8,537	$ 2,238	$ 145,844
Gain (loss) on derivatives	$ 3,657	$ 2,103	$ 963	$ —	$ 6,723
Depreciation, amortization and impairments	$ (9,883)	$ (48,187)	$ (26,963)	$ (5,791)	$ (90,824)
Capital expenditures	$ 25,196	$ 40,860	$ 4,378	$ 1,192	$ 71,626
Identifiable assets	$ 336,911	$ 1,180,796	$ 438,052	$ 58,170	$ 2,013,929

Table of Contents

CROSSTEX ENERGY, L.P.

Notes to Condensed Consolidated Financial Statements-(Continued)

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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Segment profits	$ 57,187	$ 53,523	$ 170,503	$ 145,844
General and administrative expenses	(11,277)	(16,051)	(35,669)	(43,616)
Gain (loss) on derivatives	(1,582)	1,672	(6,872)	6,723
Gain (loss) on sale of property	588	356	14,367	899
Depreciation, amortization and impairments	(28,185)	(31,155)	(83,408)	(90,824)
Operating income	$ 16,731	$ 8,345	$ 58,921	$ 19,026

(12) Immaterial Correction of Prior Period Financial Statements

During the three months ended September 30, 2010, the Company determined certain immaterial corrections were required for previously-issued financial statements as discussed below. The corrections did not impact the Company's operating income and were not material to the Company's revenues and costs for the applicable periods. The Company determined that its revenues and purchased gas and NGL costs in its previously-issued financial statements for the three and nine months ended September 30, 2009 reflected certain revenues and purchased gas and NGL costs associated with its NGL marketing activities on a net basis which should have been reflected on a gross basis. As a result both revenues and purchased gas and NGL costs were understated by $28.2 million and $56.5 million for the three and nine months ended September 30, 2009, respectively. In addition, the Company also determined that certain intercompany revenues and purchased gas costs associated with discontinued operations were not properly identified and eliminated when discontinued operations were segregated from continuing operations for the three and nine months ended September 30, 2009. These intercompany revenues and costs were incorrectly eliminated from continuing operations which resulted in equal understatements of revenues and purchased gas costs from continuing operations of $10.7 million and $40.9 million for the three and nine months ended September 30, 2009, respectively. The following table reflects the revenues, purchased gas and NGL costs and total operating costs and expenses as previously reported and as corrected for the three and nine months ended September 30, 2009:

	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
As previously reported:		
Total revenues	$ 350,900	$ 1,053,313
Purchased gas and NGLs	268,350	822,736
Total operating costs and expenses	342,555	1,034,287
Operating income	8,345	19,026
As corrected:		
Total revenues	$ 389,822	$ 1,150,728
Purchased gas and NGLs	307,272	920,151
Total operating costs and expenses	381,477	1,131,702
Operating income	8,345	19,026

Table of Contents

Item 2. ***Management's Discussion and Analysis of Financial Condition and Resultsof 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. Historically, we have operated in 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. During 2009 we sold certain non-strategic Midstream assets and the assets of the former Treating segment. Our current focus is on the gathering, processing, transmission and marketing of natural gas and natural gas liquids (NGLs) which we manage as regional reporting segments of midstream activity. Our geographic focus is in the north Texas Barnett Shale (NTX) and in Louisiana which has two reportable business segments (the Crosstex LIG and the south Louisiana processing and NGL assets or PNGL). We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas for a margin, or to gather, process, transport or market natural gas and NGLs for a fee. We define gross operating margin as operating revenue minus cost of purchased gas.

Our margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, and the volumes of NGLs handled at our fractionation facilities. We generate revenues from four primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems we own;
- processing natural gas at our processing plants;
- fractionating and marketing the recovered NGLs; and
- providing compression services.

We generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas at the market index. 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. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, we have certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as our margin. Changes in the basis spread can increase or decrease our margins. For example, we are a party to a contract with a term to 2019 to supply approximately 150 MMBtu/d of gas. We buy the gas for this contract on several different production-area indices into our north Texas pipeline and sell the gas into a different market area index. For the three and nine months ended September 30, 2010, we have recorded a loss of approximately $2.3 million and $5.4 million, respectively, on this contract due to the basis differentials between the various market prices and supply reductions, which may be more or less in future periods depending on market conditions. Reduced supplies and narrower basis spreads in recent periods have increased the losses on this contract, and greater losses on this contract could occur in future periods if these conditions persist or become worse.

We also realize gross operating margins from our processing services primarily through three different contract arrangements: processing margins (margin), percentage of liquids (POL) or fixed-fee based. Under margin contract arrangements our gross operating margins are higher during periods of high liquid prices relative to natural gas prices. Gross operating margin results under POL contracts are impacted only by the value of the liquids produced with margins higher during periods of relatively high liquids prices. Under fixed-fee based contracts our margins are driven by throughput volume. See "Item 3. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk."

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.

Our general and administrative expenses are dictated by the terms of our partnership agreement. These expenses include the costs of employee, officer and director compensation and benefits properly allocable to us, and all other expenses necessary or appropriate to the conduct of business and allocable to us. Our partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Recent Developments and Business Strategy

During the past two years, we have repositioned ourselves through asset dispositions and by recapitalizing and reorganizing our business. In response to meeting the Partnership's debt to Adjusted EBITDA target (as discussed in the Liquidity and Capital resources section of MDA), we declared a quarterly distribution of $0.25 per unit in October 2010 which is payable in November 2010 related to the three months ended September 30, 2010. We believe the resumption of our distribution is an important milestone in accessing the capital markets to support our future growth strategies.

The following transactions which occurred earlier in 2010, were key to repositioning our business and resuming the distribution:

- *Sale of Preferred Units.* On January 19, 2010, we issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions for net proceeds of $120.8 million. Crosstex Energy, GP, L.P. made a general partner contribution of $2.6 million in connection with the issuance to maintain its 2% general partner interest. The 14,705,882 preferred units are convertible by the holders thereof at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. We have the right to force conversion of the preferred units after three years if (i) the daily volume-weighted average trading price of our common units is greater than $12.75 per unit for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion and (ii) the average daily trading volume of common units must have exceeded 250,000 common units for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion. The preferred units are not redeemable. They are entitled to a quarterly distribution that is the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if we pay a cash distribution on common units. The first and second quarterly preferred unit distributions of $3.1 million were paid in cash in May 2010 and August 2010. In October 2010, we declared a third quarter preferred unit distribution of $3.7 million, equivalent to the $0.25 per unit declared for the common units, to be paid in cash in November 2010.

- *Issuance of Senior Unsecured Notes.* On February 10, 2010, we issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes due 2018 at an issue price of 97.907% to yield 9.25% to maturity, including the original issue discount (OID). Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and OID), together with borrowings under our new credit facility discussed below, were used to repay in full amounts outstanding under our old bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with our old credit facility. The notes are unsecured and unconditionally guaranteed on a senior basis by certain of our direct and indirect subsidiaries, including substantially all of our current subsidiaries. Interest payments are due semi-annually in arrears starting in August 2010. We have the option to redeem all or a portion of the notes at any time on or after February 15, 2014, at the specified redemption prices. Prior to February 15, 2014, we may redeem the notes, in whole or in part, at a "make-whole" redemption price. In addition, we may redeem up to 35.0% of the notes prior to February 15, 2013 with the cash proceeds from certain equity offerings.

- *New Credit Facility.* In February 2010, we amended and restated our secured bank credit facility with a new secured bank credit facility. The new credit facility has a borrowing capacity of $420.0 million and matures in February 2014. Obligations under the new credit facility are secured by first priority liens on substantially all of our assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in substantially all of our subsidiaries. Under the new credit facility, borrowings bear interest at our option at the British Bankers Association LIBOR Rate plus an applicable margin, or the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent's prime rate, in each case plus an applicable margin. We pay a per annum fee on all letters of credit issued under the new credit facility, and we pay a commitment fee of 0.50% per annum on the unused availability under the new credit facility. The letter of credit fee and the applicable margins for our interest rate vary quarterly based on our leverage ratio.

We also completed the sale of our east Texas assets for $39.8 million in January 2010 and recognized a $14.0 million gain on disposition.

In addition to recapitalizing our business, we are focusing on the performance and growth of our existing assets while evaluating future strategic acquisitions and selective construction and expansion opportunities. We continue our initiatives to maximize utilization of our assets by improving operations and reducing operating costs. We also entered into a 10-year firm transportation agreement in June 2010 with a major Barnett Shale producer for an additional 50 MMcf/d of natural gas on our gathering system in north Texas. We are constructing a compressor station on an existing gathering line at an estimated cost of less than $10.0 million to accommodate such transportation requirements. The project is scheduled to be completed and operational in the first quarter of 2011. The annual cash flow from the agreement is expected to be approximately $8.0 million. We are also expanding our natural gas gathering system in the Barnett Shale with a $25.0 million 15-mile pipeline project. The project is supported by volumetric commitments from a major gas producer and is expected to have throughput of approximately 100 Bcf of gas during the first four years of operation. The project is scheduled to be completed in the first quarter of 2011.

Our future operations may be negatively impacted by recent developments in the energy industry. In light of the explosion and fire on the drilling rig Deepwater Horizon in the Gulf of Mexico, as well as recent incidents involving the release of natural gas and fluids as a result of drilling activities in the Marcellus Shale, there has been a variety of regulatory initiatives at the federal and state level to restrict oil and gas drilling operations in certain locations. Any increased regulation or suspension of oil and gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arises out of these incidents or otherwise could result in delays and higher operating costs. Such costs or significant delays could have a material adverse effect on our business, financial condition and results of operations.

Results of Operations

Set forth in the table below is certain financial and operating data for the periods indicated, which excludes financial and operating data deemed discontinued operations. We manage our operations by focusing on gross operating margin which we define as operating revenue minus cost of purchased gas and NGLs as reflected in the table below. We have also provided a reconciliation of this non-GAAP measure to its most directly comparable GAAP measure of operating income below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(Dollars in millions)			
LIG Segment				
Revenues	$ 250.4	$ 215.6	$ 740.0	$ 659.9
Purchased gas	(221.6)	(187.2)	(653.5)	(589.9)

Total gross operating margin	$ 28.8	$ 28.4	$ 86.5	$ 70.0
NTX Segment				
Revenues	$ 106.0	$ 120.6	$ 302.6	$ 376.8
Purchased gas	(66.2)	(79.9)	(184.4)	(253.9)
Total gross operating margin	$ 39.8	$ 40.7	$ 118.2	$ 122.9
PNGL Segment				
Revenues	$ 137.0	$ 84.1	$ 451.2	$ 195.4
Purchased gas and NGLs	(122.0)	(72.2)	(407.0)	(162.0)
Total gross operating margin	$ 15.0	$ 11.9	$ 44.2	$ 33.4
Corporate				
Revenues	$ (38.7)	$ (30.5)	$ (128.3)	$ (81.4)
Purchased gas	38.7	32.0	128.3	85.7
Total gross operating margin	$ —	$ 1.5	$ —	$ 4.3
Total				
Revenues	$ 454.7	$ 389.8	$ 1,365.5	$ 1,150.7
Purchased gas	(371.1)	(307.3)	(1,116.6)	(920.1)
Total gross operating margin	$ 83.6	$ 82.5	$ 248.9	$ 230.6

Table of Contents

	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
	(Dollars in millions)			
Midstream Volumes (MMBtu/d):				
LIG				
Gathering and Transportation	883,000	898,000	895,000	906,000
Processing	284,000	268,000	285,000	262,000
NTX				
Gathering and Transportation	1,080,000	1,098,000	1,079,000	1,115,000
Processing	224,000	220,000	210,000	224,000
PNGL				
Processing	878,000	779,000	886,000	697,000
Commercial Services Volumes	123,000	95,000	73,000	87,000
Corporate				
Gathering and Transportation	—	31,000	—	33,000

The following table provides a reconciliation of gross operating margin to operating income.

	Three Months Ended September 30, 2010	2009	Nine Months Ended September 30, 2010	2009
Total gross operating margin	$ 83.6	$ 82.5	$ 248.9	$ 230.6
Add (deduct):				
Operating expenses	(26.4)	(29.0)	(78.4)	(84.7)
General and administrative expenses	(11.3)	(16.1)	(35.7)	(43.6)
Gain on sale of property	0.6	0.4	14.4	0.9
Gain (loss) on derivatives	(1.6)	1.7	(6.9)	6.7
Depreciation, amortization and impairments	(28.2)	(31.2)	(83.4)	(90.9)
Operating income	$ 16.7	$ 8.3	$ 58.9	$ 19.0

Three Months Ended September 30, 2010 Compared to Three Months Ended September 30, 2009

Gross Operating Margin and NGL Marketing Activities. Gross operating margin was $83.6 million for the three months ended September 30, 2010 compared to $82.5 million for the three months ended September 30, 2009, an increase of $1.1 million, or 1.3% . The increase was primarily due to the growth in our NGL marketing activities.

- The LIG segment contributed gross operating margin growth of $0.4 million for the three months ended September 30, 2010 over the same period in 2009. Approximately $1.9 million of gross operating margin growth on the gathering and transmission system was primarily due to improved pricing and higher firm transport volumes on the northern part of the system related to the Haynesville Shale. This increase was offset by a gross operating margin decline of $1.2 million at the processing plants on the system, which was mainly driven by a lower NGL to gas ratio in third quarter 2010 compared to third quarter 2009.

- The NTX segment had a gross operating margin decline of $0.9 million for the three months ended September 30, 2010 over the same period in 2009. The margin impact of lower gathering volumes was offset by system optimization as well as higher volumes on the transmission system.

- The PNGL segment had gross operating margin growth of $3.1 million for the comparable periods due to increased liquids marketing activity and the continued favorable processing environment. The primary contributor to this gross operating margin growth in the PNGL segment is the $1.8 million increase from NGL marketing activities. In addition, the Riverside facility had a gross operating margin increase of $1.2 million for the comparable period due to fractionation fees related to the increase in processed volumes.

Table of Contents

- The corporate segment reported a gross operating margin decrease of approximately $1.5 million for the three months ended September 30, 2010 compared to the same period in 2009 due to gross operating margin associated with sold assets.

Operating Expenses. Operating expenses were $26.5 million for the three months ended September 30, 2010 compared to $29.0 million for the three months ended

September 30, 2009, a decrease of $2.5 million, or 8.8%. The decrease is primarily a result of the following:

- Reduction in rental costs of $3.1 million due to the buy out of the Eunice plant operating lease in October 2009, the renegotiation of compressor rental rates and the consolidation of compressor operations for facilities that were not fully utilized;
- Decrease in labor costs of $0.8 million primarily due to workforce reductions in 2009;
- Elimination of operating costs of $0.5 million between 2010 and 2009 as a result of the January 2010 sale of the east Texas system; offset by
- Increases in repair and maintenance costs of $1.5 million including scheduled overhauls of equipment and other repairs.

General and Administrative Expenses. General and administrative expenses were $11.3 million for the three months ended September 30, 2010 compared to $16.1 million for the three months ended September 30, 2009, a decrease of $4.8 million, or 29.7%. The decrease is primarily a result of the following:

- Labor cost decreases of $3.0 million which includes the impact of workforce reductions;
- Rent cancellation fees incurred during 2009 of $0.3 million; and
- Professional fees and services, primarily legal, decrease of $1.0 million

Gain/Loss on Derivatives. We had a loss on derivatives of $1.6 million for the three months ended September 30, 2010 compared to a gain of $1.6 million for the three months ended September 30, 2009. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Three Months Ended September 30,			
	2010		2009	
	Total	Realized	Total	Realized
Basis swaps	$ —	$ (0.5)	$ (1.8)	$ (0.7)
Processing margin hedges	1.7	0.5	0.5	0.8
Other	(0.1)	—	0.2	(0.1)
Net (gains) losses related to commodity swaps	$ 1.6	$ —	$ (1.1)	$ —
Derivative (gains) losses included in income from discontinued operations	—	—	(0.5)	—
Derivative (gains) losses from continuing operations	$ 1.6	$ —	$ (1.6)	$ —

Depreciation and Amortization. Depreciation and amortization expenses were $28.2 million for the three months ended September 30, 2010 compared to $30.2 million for the three months ended September 30, 2009, a decrease of $2.1 million, or 6.8%. The decrease includes $2.7 million due to a change in estimated depreciable lives based on the 2009 depreciation study regarding processing plants but is partially offset by $0.5 million depreciation on the Eunice natural gas liquids processing plant and fractionation facility purchased during the fourth quarter of 2009.

Interest Expense. Interest expense was $20.3 million for the three months ended September 30, 2010 compared to $27.9 million for the three months ended September 30, 2009, a decrease of $7.6 million, or 27.0%. The decrease in interest expense between the periods was primarily due to expense associated with interest rate swaps included in third quarter 2009 and reductions in debt outstanding beyond amounts associated with asset sales. Net interest expense consists of the following (in millions):

	Three Months Ended September 30,	
	2010	2009
Senior notes (secured and unsecured)	$ 16.9	$ 12.6
Bank credit facility	1.4	10.6
PIK interest on senior secured notes	—	1.6
Mark to market interest rate swaps	—	1.0
Amortization of debt issue costs	1.5	2.0
Other	0.6	0.1
Total	$ 20.3	$ 27.9

Discontinued Operations. During 2009, we sold certain non-strategic assets. In accordance with FASB ASC 360-10-05-4 the results of operations related to the assets sold are presented in income from discontinued operations for the three months ended September 30, 2009. Revenues, operating expenses, general and administrative expenses associated directly to the assets sold, depreciation and amortization, allocated Texas margin tax and allocated interest are reflected in the income from discontinued operations. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are the components of revenues and earnings from discontinued operations and operating data (dollars in millions):

	Three Months Ended September 30, 2009
Midstream revenues	$ 43.7
Treating revenues	$ 13.9
Loss from discontinued operations, net of tax	$ (4.0)
Gain on sale of discontinued operations, net of tax	$ 97.4
Gathering and Transmission Volumes (MMBtu/d)	563,000
Processing Volumes (MMBtu/d)	178,000

Nine Months Ended September 30, 2010 Compared to Nine Months Ended September 30, 2009

Gross Operating Margin and NGL Marketing Activities. Gross operating margin was $248.9 million for the nine months ended September 30, 2010 compared to $230.6 million for the nine months ended September 30, 2009, an increase of $18.3 million, or 7.9%. The increase was primarily due to the continuation of a favorable gas processing environment and growth in our gathering and transmission systems.

- The LIG segment contributed gross operating margin growth of $16.5 million for thenine months ended September 30, 2010 over the same period in 2009. Approximately $11.1 million of this increase results from the gathering and transmission system due primarily to improved pricing and higher volumes on the northern part of the system related to Haynesville Shale. The Plaquemine and Gibson processing plants on the system contributed gross operating margin growth of $3.0 million and $2.6 million, respectively. These increases are attributed to the favorable processing environment in the first nine months of the year.

- The NTX segment had a gross operating margin decline of $4.7 million for thenine months ended September 30, 2010 over the same period in 2009. The decrease is primarily due to the decline in througput volumes combined with a change in the basis spread between various market prices.

· The PNGL segment had gross operating margin growth of $10.8 million for the comparable periods due to increased liquids marketing activity and the continued favorable processing environment. The primary contributor to this gross operating margin growth in the PNGL segment is a $5.2 million increase from NGL marketing activities noted above. In addition, the Riverside, Pelican and Eunice facilities had gross operating margin increases of $3.2 million, $2.3 million and $1.6 million, respectively, due to increased inlet volumes for all three facilities. These increases were offset in part by a gross operating margin decline of $1.9 million at the Sabine Pass plant due primarily to lower inlet volumes.

· The corporate segment reported a gross operating margin decrease of approximately $4.3 million for thenine months ended September 30, 2010 compared to the same period in 2009 due to gross operating margin associated with sold assets.

Table of Contents

Operating Expenses. Operating expenses were $78.4 million for the nine months ended September 30, 2010 compared to $84.7 million for the nine months ended September 30, 2009, a decrease of $6.4 million, or 7.5%. The decrease is primarily a result of the following:

· Reduction in rental costs of $8.0 million due to the buy of out the Eunice plant operating lease in October 2009, the renegotiation of compressor rental rates and the consolidation of compressor operations for facilities that were not fully utilized;
· Elimination of operating costs of $3.6 million between 2010 and 2009 as a result of the April 2009 sale of the Arkoma system and the January 2010 sale of the east Texas system; and
· Increases in repair and maintenance costs of $5.0 million including scheduled overhauls of equipment and other repairs.

General and Administrative Expenses. General and administrative expenses were $35.7 million for the nine months ended September 30, 2010 compared to $43.6 million for the nine months ended September 30, 2009, a decrease of $7.9 million, or 18.2%. The decrease is primarily a result of the following:

· Labor cost decrease of $6.0 million which includes the impact of workforce reductions;
· Bad debt reduction of $1.6 million;
· Rent cancellation fees incurred during 2009 of $1.1 million;
· Professional fees, primarily legal fees, decreased $0.8 million; and
· Stock based compensation increase of $1.0 million for new grants.

Gain on sale of Property from Continuing Operations. Gains on sale of property were $14.3 million for the nine months ended September 30, 2010 compared to $0.9 million for the nine months ended September 30, 2009. The gain on sale of property for the nine months ended September 30, 2010 was related to the sale of our east Texas assets in January 2010.

Gain/Loss on Derivatives. We had a loss on derivatives of $6.9 million for the nine months ended September 30, 2010 compared to a gain of $6.7 million for the nine months ended September 30, 2009. The derivative transaction types contributing to the net (gain) loss are as follows (in millions):

	Nine Months Ended September 30,			
	2010		2009	
	Total	Realized	Total	Realized
Basis swaps	$ 4.8	$ 1.8	$ (3.6)	$ (1.7)
Processing margin hedges	2.3	4.0	(3.2)	(3.2)
Other	(0.2)	0.1	(0.2)	(1.4)
Net (gains) losses related to commodity swaps	$ 6.9	$ 5.9	$ (7.0)	$ (6.3)
Derivative losses included in income from discontinued operations	—	—	0.3	0.5
Derivative (gains) losses from continuing operations	$ 6.9	$ 5.9	$ (6.7)	$ (5.8)

Impairments. Impairment expense was $1.3 million for the nine months ended September 30, 2010 and $0.9 million during the nine months ended September 30, 2009. The impairment in 2010 primarily relates to the write down of certain excess pipe inventory prior to its sale.

Depreciation and Amortization. Depreciation and amortization expenses were $82.1 million for the nine months ended September 30, 2010 compared to $89.9 million for the nine months ended September 30, 2009, a decrease of $7.8 million, or 8.7%. The decrease includes $7.9 million from the decision made in the fourth quarter of 2009 to change estimated depreciable lives based on the 2009 depreciation study regarding processing plants and $1.5 million from the sale of the east Texas assets. These decreases were partially offset by $1.6 million of depreciation expense associated with the Eunice natural gas liquids processing plant and fractionation facility purchased during the fourth quarter of 2009.

Interest Expense. Interest expense was $67.2 million for the nine months ended September 30, 2010 compared to $67.1 million for the nine months ended September 30, 2009. Net interest expense consists of the following (in millions):

Table of Contents

	Nine Months Ended September 30,	
	2010	2009
Senior notes (secured and unsecured)	$ 45.9	$ 35.6
Bank credit facility	8.8	25.0
PIK interest on senior secured notes	1.4	3.7
Mark to market interest rate swaps	(22.4)	(2.5)
Realized interest rate swaps	26.5	—
Amortization of debt issue costs	5.2	5.6
Other	1.8	(0.3)
Total	$ 67.2	$ 67.1

Loss on Extinguishment of Debt. We recognized a loss on extinguishment of debt during the nine months ended September 30, 2010 and 2009 of $14.7 million and $4.7 million, respectively. In February 2010, we repaid our existing credit facility and senior secured notes which resulted in make-whole interest payments on our senior secured notes and the write-off of unamortized debt costs totaling $14.7 million. The loss of $4.7 million on extinguishment of debt incurred in the nine months ended September 30, 2009 related to the amendment of our old credit facility and the senior secured notes in February 2009.

Discontinued Operations. During 2009, we sold certain non-strategic assets. In accordance with FASB ASC 360-10-05-4 the results of operations related to the assets sold are presented in income from discontinued operations for the nine months ended September 30, 2009. Revenues, operating expenses, general and administrative expenses associated directly to the assets sold, depreciation and amortization, allocated Texas margin tax and allocated interest are reflected in the income from discontinued operations. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are the components of revenues and earnings from discontinued operations and operating data (dollars in millions):

	Nine Months Ended September 30, 2009
Midstream revenues	$ 327.2
Treating revenues	$ 45.7
Income from discontinued operations, net of tax	$ 4.4
Gain from sales of discountinued operations net, of tax	$ 97.4
Gathering and Transmission Volumes (MMBtu/d)	565,000
Processing Volumes (MMBtu/d)	191,000

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, 2009.

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $46.3 million and $62.7 million for the nine months ended September 30, 2010 and 2009, respectively. Income before non-cash income and expenses and changes in working capital for comparative periods were as follows (in millions):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Income before non-cash income and expenses	$ 29.3	$ 72.7
Changes in working capital	$ 17.0	$ (10.0)

The primary reason for the decrease in cash flow from income before non-cash income and expenses of $43.4 million from 2009 to 2010 relates to payments for settlements of interest rate swaps, make-whole payments, and PIK notes.

Cash Flows from Investing Activities. Net cash provided by investing activities was $32.9 million for the nine months ended September 30, 2010 and net cash provided by investing activities was $164.2 million for the nine months ended September 30, 2009. Our primary investing outflows were capital expenditures, net of accrued amounts, as follows (in millions):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Growth capital expenditures	$ 23.8	$ 83.6
Maintenance capital expenditures	6.0	7.2
Total	$ 29.8	$ 90.8

Cash flows from investing activities for the nine months ended September 30, 2010 and 2009 also includes proceeds from property sales of $60.0 million and $245.3 million, respectively. The east Texas assets and a non-operational processing plant held in inventory were sold in 2010 for $39.8 million and $19.5 million, respectively. The Arkoma asset was sold in the first quarter of 2009 for $11.0 million and our south Texas, Mississippi and Alabama assets were sold in the third quarter 2009 for $214.0 million.

Cash Flows from Financing Activities. Net cash used in financing activities was $67.7 million and $227.6 million for the nine months ended September 30, 2010 and 2009, respectively. Financing activities during 2010 primarily relate to the issuance of senior unsecured notes, sale of preferred units and establishment of a new credit facility and repaying our prior credit facility and senior secured notes. Financing activities during 2009 primarily relate to funding of capital expenditures. Our financings have primarily consisted of borrowings and repayments under our old and new bank credit facilities, borrowings and repayments under capital lease obligations, senior secured note repayments, senior unsecured note borrowings and debt refinancing costs during 2010 and 2009 as follows (in millions):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Net borrowings (repayments) under bank credit facilities	$ (541.8)	$ (107.5)
Senior secured note repayments	(316.5)	76.0
Senior unsecured note borrowings (net of discount on the note)	711.0	—
Net borrowings (repayments) under capital lease obligations	(1.7)	(0.4)
Debt refinancing costs	(28.5)	(13.8)

Historically distributions to unitholders and our general partner represented a significant use of cash in financing activities. In the first quarter of 2009, we ceased making distributions to common unitholders due to liquidity issues and because the terms of our old credit facility and senior secured note agreement restricted our ability to make distributions unless certain conditions were met. During the second and third quarters of 2010, we paid quarterly distributions on our preferred units of $3.1 million per quarter. In October 2010, we declared a quarterly distribution of $0.25 per unit (common and preferred) payable in cash in November 2010. Total cash distributions made during the nine months ended September 30, 2010 and 2009 were as follows (in millions):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Common units	$ —	$ 11.4
Preferred units	6.2	—

General partner		—		0.2
Total	$	6.2	$	11.6

Our new credit facility does not limit our ability to make distributions as long as we are not in default of such facility. The indenture governing our senior unsecured notes provide the ability to pay distributions if a minimum fixed charged coverage ratio is met, and also provides baskets to make payments if the minimum is not met. However, we have established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA (earnings before interest, income taxes, depreciation and amortization, impairments, non-cash mark-to-market items and other miscellaneous non-cash items) of less than 4.0 to 1.0, and we do

not currently plan to make cash distributions on our outstanding units unless such ratio is less than 4.5 to 1.0 (pro forma for any distribution). The Partnership's ratio of debt to Adjusted EBITDA was 4.2 to 1.0 as of September 30, 2010. The preferred distribution payments paid during 2010 and the declared distributions related to our third quarter of 2010 are in compliance with our financial guidelines, as we achieved in each period a ratio of debt to Adjusted EBITDA of less than 4.5 to 1.0 (on a pro forma basis considering the payment of the relevant cash distributions).

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. We borrow money under our $420.0 million new credit facility to fund checks as they are presented. As of September 30, 2010, we had approximately $320.1 million of available borrowing capacity under this facility. Changes in drafts payable for the nine months ended 2010 and 2009 were as follows (in millions):

	Nine Months Ended September 30,			
		2010		2009
Decrease in drafts payable	$	5.2	$	17.9

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of September 30, 2010.

Capital Requirements. During the nine months ended September 30, 2010 our growth capital investments were $23.8 million which were funded by internally generated cash flow. Our current capital spending projection for the next twelve months includes approximately $56.0 million of identified growth projects. Although we may identify more growth projects over the next twelve month period, we still do not anticipate that our capital expenditures will exceed $100.0 million during this twelve month planning period.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of September 30, 2010, is as follows (in millions):

	Payments Due by Period													
		Total		2010		2011		2012		2013		2014		Thereafter
Long-term debt obligations	$	732.1	$	—	$	7.1	$	—	$	—	$	—	$	725.0
Interest payable on fixed long-term debt obligations		482.2		0.3		64.7		64.3		64.3		64.3		224.3
Capital lease obligations		40.8		1.1		4.6		4.6		4.6		4.6		21.3
Operating lease obligations		47.4		3.4		13.7		9.8		6.6		5.0		8.9
Uncertain tax position obligations		3.2		—		3.2		—		—		—		—
Total contractual obligations	$	1,305.7	$	4.8	$	93.3	$	78.7	$	75.5	$	73.9	$	979.5

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

Indebtedness

As of September 30, 2010 and December 31, 2009, long-term debt consisted of the following (in millions):

		September 30, 2010		December 31, 2009
Bank credit facility, interest based on Prime and/or LIBOR plus an applicable margin; interest rate at December 31, 2009 was 6.75%	$	—	$	529.6
New credit facility, interest based on Prime and/or LIBOR plus an applicable margin; interest rate at September 30, 2010 was 6.0%		—		—
Senior secured notes (including PIK notes (1) of $9.5 million), weighted average interest rate at December 31 2009 was 10.5%		—		326.0
Senior unsecured notes, net of discount of $13.9 million, which bears interest at the rate of 8.875%		711.0		—
Series B secured note assumed in the Eunice transaction, which bears interest at the rate of 9.5%		7.1		18.1
		718.1		873.7
Less current portion		(7.1)		(28.6)
Debt classified as long-term	$	711.0	$	845.1

(1) The senior secured notes began accruing additional interest of 1.25% per annum in February 2009 in the form of an increase in the principal amounts thereof (the "PIK notes"). These notes were paid in full in February 2010.

New Credit Facility. As of September 30, 2010, we had a new bank credit facility with a borrowing capacity of $420.0 million that matures in February 2014. As of September 30, 2010, there was $99.9 million in letters of credit issued and outstanding under the new bank credit facility, leaving approximately $320.1 million available for future borrowing. The new bank credit facility is guaranteed by substantially all of our subsidiaries.

Recent Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update (ASU) 2010-06, Improving Disclosures about Fair Value Measurements, which amends FASB ASC

Topic 820, Fair Value Measurements and Disclosures. The ASU requires reporting entities to make new disclosures about recurring or nonrecurring fair-value measurements including significant transfers into and out of Level 1 and Level 2 fair-value measurements and information about purchases, sales, issuances, and settlements on a gross basis in the reconciliation of Level 3 fair-value measurements. The ASU also clarifies existing fair-value measurement disclosure guidance about the level of disaggregation, inputs, and valuation techniques. We have evaluated the ASU and determined that we are not currently impacted by the update.

Disclosure Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements. 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, 2009, and those set forth in Part II, "Item 1A. Risk Factors" of this report, if any, 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 exposed to the risk of changes in interest rates on our floating rate debt.

On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank") into law, a part of which relates to increased regulation of the markets for derivative products of the type we use to manage areas of market risk. While the Commodity Futures Trading Commission has yet to issue regulations to implement this increased regulation, Dodd-Frank may result in increased costs to us to implement our market risk management strategy.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate new bank credit facility. At September 30, 2010, our new bank credit facility had no outstanding borrowings.

At September 30, 2010, we had total fixed rate debt obligations of $718.1 million, consisting of our senior unsecured notes with an interest rate of 8.875% and a series B secured note with an interest rate of 9.5%. The fair value of these fixed rate obligations was approximately $764.7 million as of September 30, 2010. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of such debt by $24.4 million.

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. We currently process gas under three main types of contractual arrangements:

1. Processing margin 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") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR. 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. However, we mitigate our risk of processing natural gas when margins are negative primarily through our ability to bypass processing when it is not profitable for us, or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.

2. Percent of liquids 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 liquids contracts, but do decline during periods of low NGL prices.

3. Fee based contracts: Under these contracts we have no commodity price exposure and are paid a fixed fee per unit of volume that is processed.

The gross operating margin presentation in the table below is calculated net of results from discontinued operations. Gas processing margins by contract types and gathering and transportation margins as a percent of total gross operating margin for the comparative year-to-date periods are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Gathering and transportation margin	65.4%	66.3%	62.8%	68.0%
Gas processing margins:				
Processing margin	9.6%	9.5%	12.1%	7.7%
Percent of liquids	9.8%	11.7%	10.9%	12.4%
Fee based	15.2%	12.5%	14.2%	11.9%
Total gas processing	34.6%	33.7%	37.2%	32.0%
Total	100.0%	100.0%	100.0%	100.0%

We have hedges in place at September 30, 2010 covering a portion of the liquids volumes we expect to receive under percent of liquids (POL) contracts as set forth in the following table. The relevant payment index price is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

	Notional		Fair Value

Period	Underlying	Volume	We Pay	We Receive*	Asset/(Liability)
					(In thousands)
October 2010 – December 2010	Propane	28 (MBbls)	Index	$ 0.9700 /gal	$ (281)
October 2010 – December 2010	Normal Butane	10 (MBbls)	Index	$ 1.2725 /gal	(92)
October 2010 – December 2010	Natural Gasoline	5 (MBbls)	Index	$ 1.4835 /gal	(77)
					$ (450)

*weighted average

Period	Underlying	Notional Volume	We Pay	We Receive*	Fair Value Asset/(Liability)
					(In thousands)
January 2011 – December 2011	Ethane	30 (MBbls)	Index	$ 0.4693 /gal	$ 1
January 2011 – December 2011	Propane	16 (MBbls)	Index	$ 1.0076 /gal	(72)
January 2011 – December 2011	Normal Butane	18 (MBbls)	Index	$ 1.4396 /gal	1
January 2011 – December 2011	Natural Gasoline	26 (MBbls)	Index	$ 1.7543 /gal	(97)
					$ (167)

*weighted average

We have hedged our exposure to declines in prices for NGL volumes produced for our account. The NGL volumes hedged, as set forth above, focus on our POL contracts. We hedge our POL exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total POL volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. As of September 30, 2010, we have hedged 45.4% of our hedgeable volumes at risk through December 2010 (20.5% of total volumes at risk through December 2010). We have also hedged 24.4% of our hedgeable volumes at risk for the first six months of 2011 (12.0% of total volumes at risk for the first six months of 2011) and 16.1% of our hedgeable volumes at risk for the last six months of 2011 (8.4% of total volumes at risk for the last six months of 2011).

Additional hedges were executed in October 2010 to hedge additional exposure for the remainder of 2010 and for all of 2011. As a result, at the end of October 2010, we had hedged 76.9% of our hedgeable volumes at risk for the remainder of 2010 (34.8% of total volumes at risk), 52.9% of our hedgeable volumes at risk for the first six months of 2011 (25.9% of total volumes at risk) and 62.7% of our hedgeable volumes at risk for the last six months of 2011 (32.5% of total volumes at risk). For the last six months of 2011, 38.9% of the hedging on our hedgeable volumes at risk (20.1% of total volumes at risk) was done via the purchase of puts in October. All other hedges executed in October were swaps.

We also have hedges in place at September 30, 2010 covering the fractionation spread risk related to our processing margin contracts as set forth in the following table:

Period	Underlying	Notional Volume		We Pay	We Receive	Fair Value Asset/(Liability)
						(In thousands)
October 2010 - December 2010	Ethane	28	(MBbls)	Index	$ 0.4677 /gal*	$ (72)
October 2010 - December 2010	Propane	19	(MBbls)	Index	$ 0.9668 /gal*	(197)
October 2010 - December 2010	Normal Butane	13	(MBbls)	Index	$ 1.2693 /gal*	(125)
October 2010 - December 2010	Natural Gasoline	13	(MBbls)	Index	$ 1.5896 /gal*	(130)
October 2010 - December 2010	Natural Gas	3,757	(MMBtu/d)	$ 6.4894 /MMBtu*	Index	(869)
						$ (1,393)

*weighted average

Period	Underlying	Notional Volume		We Pay	We Receive	Fair Value Asset/(Liability)
						(In thousands)
January 2011 - December 2011	Ethane	9	(MBbls)	Index	$ 0.4633 /gal*	$ (13)
January 2011 - December 2011	Propane	27	(MBbls)	Index	$ 1.0615 /gal*	(77)
January 2011 - December 2011	Iso Butane	6	(MBbls)	Index	$ 1.4991 /gal*	4
January 2011 - December 2011	Normal Butane	10	(MBbls)	Index	$ 1.4342 /gal*	(9)
January 2011 - December 2011	Natural Gasoline	12	(MBbls)	Index	$ 1.7998 /gal*	(21)
January 2011 - December 2011	Natural Gas	875	(MMBtu/d)	$ 5.4140 /MMBtu*	Index	(326)
						$ (442)

Table of Contents

* weighted average

In relation to our fractionation spread risk, as set forth above, we have hedged 43.8% of our hedgeable liquids volumes at risk through December 2010 (19.0% of total liquids volumes at risk) and 47.5% of the related hedgeable PTR volumes through December 2010 (21.1% of total PTR volumes). We have also hedged 13.9% of our hedgeable liquids volumes at risk for the first six months of 2011 (6.3% of total liquids volumes at risk) and 15.3% of the related hedgeable PTR volumes for the first six months of 2011 (7.3% of total PTR volumes). In addition, we have hedged 5.2% of our hedgeable liquids volumes at risk for the last six months of 2011 (2.4% of total liquids volumes at risk) and 6.2% of the related hedgeable PTR volumes for the last six months of 2011 (3.0% of total PTR volumes).

Additional hedges were executed in October 2010 to hedge additional exposure for the remainder of 2010 and for all of 2011. As a result, at the end of October 2010, we had hedged 54.1% of our hedgeable liquids volumes at risk for the remainder of 2010 (23.4% of total liquids volumes at risk) and 55.0% of the related hedgeable PTR volumes for the remainder of 2010 (24.5% of total PTR volumes). Also, at the end of October 2010, we had hedged 38.3% of our hedgeable liquids volumes at risk for the first six months of 2011 (17.2% of total liquids volumes at risk) and 38.4% of the related hedgeable PTR volumes for the first six months of 2011 (18.3% of total PTR volumes).

We are also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transport services. Approximately 8.0% 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.

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 natural gas bought and sold on the same basis. However, it is normal to experience fluctuations in the volumes of natural 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.

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 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.

As of September 30, 2010, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $2.1 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in an increase of approximately $1.1 million in the net fair value liability of these contracts as of September 30, 2010 to a net fair value liability of approximately $3.2 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 pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report (September 30, 2010), our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported,

Table of Contents

within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting that occurred in the three months ended September 30, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. *Legal Proceedings*

We are 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 our financial position or results of operations.

For a discussion of certain litigation and similar proceedings, please refer to Note 10, “Commitments and Contingencies,” of the Notes to Condensed Consolidated Financial Statements, which is incorporated by reference herein.

Item 1A. *Risk Factors*

Information about risk factors for the three months ended September 30, 2010 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, 2009.

Table of Contents

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	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.4	—	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008).

3.5	—	Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
3.6	—	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).
3.7	—	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, file No. 000-50067).
3.8	—	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).
3.9	—	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).
3.10	—	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).
3.11	—	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).
3.12	—	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of January 19, 2010 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010).
4.1	—	Registration Rights Agreement, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010).
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.

Table of Contents

SIGNATURES

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

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

November 4, 2010

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 such 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 the 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 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 control over financial reporting.

/s/ BARRY E. DAVIS
BARRY E. DAVIS,
President and Chief Executive Officer
(principal executive officer)

Date: November 4, 2010

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 such 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 the 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 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 control over financial reporting.

/s/ WILLIAM W. DAVIS

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

Date: November 4, 2010

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 September 30, 2010 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 results of operations of the Registrant.

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

November 4, 2010

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

November 4, 2010

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.