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# 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 March 31, 2013**

**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**<br>(State of organization) | **16-1616605**<br>(I.R.S. Employer Identification No.) |
| **2501 CEDAR SPRINGS**<br>**DALLAS, TEXAS**<br>(Address of principal executive offices) | **75201**<br>(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. (Check one):

| | |
|---|---|
| Large accelerated filer ☒ | Accelerated filer ☐ |
| Non-accelerated filer ☐<br>(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 April 25, 2013, the Registrant had 79,509,286 common units outstanding.

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## CROSSTEX ENERGY, L.P.

### Condensed Consolidated Balance Sheets

| | March 31, 2013 (Unaudited) | December 31, 2012 |
| --- | --- | --- |
| | (In thousands) | |
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 42 | $ 124 |
| Accounts receivable: | | |
| Trade, net of allowance for bad debt of $683 and $535, respectively | 69,001 | 63,690 |
| Accrued revenue and other | 139,824 | 155,720 |
| Fair value of derivative assets | 2,698 | 3,234 |
| Natural gas and natural gas liquids inventory, prepaid expenses and other | 14,392 | 11,853 |
| Assets held for disposition | — | 22,599 |
| Total current assets | 225,957 | 257,220 |
| Property and equipment, net of accumulated depreciation of $526,264 and $503,867, respectively | 1,566,695 | 1,471,248 |
| Fair value of derivative assets | 9 | — |
| Intangible assets, net of accumulated amortization of $274,633 and $263,305, respectively | 413,676 | 425,005 |
| Goodwill | 152,323 | 152,627 |
| Investment in limited liability company | 98,968 | 90,500 |
| Other assets, net | 26,016 | 25,989 |
| Total assets | $ 2,483,644 | $ 2,422,589 |
| **LIABILITIES AND PARTNERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable, drafts payable and other | $ 25,935 | $ 32,265 |
| Accrued gas and crude oil purchases | 123,368 | 140,344 |
| Fair value of derivative liabilities | 255 | 1,310 |
| Other current liabilities | 75,419 | 71,340 |
| Accrued interest | 14,971 | 26,712 |
| Liabilities held for disposition | — | 3,572 |
| Total current liabilities | 239,948 | 275,543 |
| Long-term debt | 977,780 | 1,036,305 |
| Other long-term liabilities | 29,543 | 30,256 |
| Deferred tax liability | 71,378 | 71,404 |
| Fair value of derivative liabilities | 12 | — |
| Commitments and contingencies | — | — |
| Partners' equity | 1,164,983 | 1,009,081 |
| Total liabilities and partners' equity | $ 2,483,644 | $ 2,422,589 |

See accompanying notes to condensed consolidated financial statements.



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## CROSSTEX ENERGY, L.P.

### Condensed Consolidated Statements of Operations

| | Three Months Ended March 31, 2013 | 2012 |
| --- | --- | --- |
| | (Unaudited) (In thousands, except per unit amounts) | |
| Revenues | $ 445,689 | $ 371,709 |
| Operating costs and expenses: | | |
| Purchased gas, NGLs and crude oil | 341,022 | 271,956 |
| Operating expenses | 37,336 | 27,806 |
| General and administrative | 18,236 | 14,963 |
| (Gain) loss on sale of property | 11 | (98) |
| Loss on derivatives | 472 | 2,169 |
| Depreciation and amortization | 33,726 | 32,178 |
| Total operating costs and expenses | 430,803 | 348,974 |
| Operating income | 14,886 | 22,735 |
| Other income (expense): | | |
| Interest expense, net of interest income | (20,271) | (19,382) |
| Equity in losses of limited liability company | (78) | — |
| Other income | 220 | 12 |
| Total other expense | (20,129) | (19,370) |
| Income (loss) before non-controlling interest and income taxes | (5,243) | 3,365 |
| Income tax provision | (709) | (424) |
| Net income (loss) | (5,952) | 2,941 |
| Less: Net loss attributable to the non-controlling interest | — | (38) |

| | 2013 | 2012 |
|---|---|---|
| Net income (loss) attributable to Crosstex Energy, L.P. | $ (5,952) | $ 2,979 |
| Preferred interest in net income (loss) attributable to Crosstex Energy, L.P. | $ 7,079 | $ 4,853 |
| General partner interest in net income (loss) | $ (1,244) | $ (71) |
| Limited partners' interest in net income (loss) attributable to Crosstex Energy, L.P. | $ (11,787) | $ (1,803) |
| Net loss attributable to Crosstex Energy, L.P. per limited partners' unit: | | |
| Basic and diluted per common unit | $ (0.15) | $ (0.03) |

See accompanying notes to condensed consolidated financial statements.



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## CROSSTEX ENERGY, L.P.

### Consolidated Statements of Comprehensive Income (Loss)

| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| | (Unaudited) (In thousands) | |
| Net income (loss) | $ (5,952) | $ 2,941 |
| Hedging (gains) losses reclassified to earnings | (259) | 354 |
| Adjustment in fair value of derivatives | 132 | (39) |
| Comprehensive income (loss) | (6,079) | 3,256 |
| Comprehensive loss attributable to non-controlling interest | — | 38 |
| Comprehensive income (loss) attributable to Crosstex Energy, L.P. | $ (6,079) | $ 3,294 |

See accompanying notes to condensed consolidated financial statements.



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## CROSSTEX ENERGY, L.P.

### Consolidated Statements of Changes in Partners' Equity
### Three Months Ended March 31, 2013

| | Common Units | | Preferred Units | | General Partner Interest | | Accumulated Other Comprehensive Income (loss) | Total |
|---|---|---|---|---|---|---|---|---|
| | $ | Units | $ | Units | $ | Units | | |
| | (Unaudited) (In thousands) | | | | | | | |
| Balance, December 31, 2012 | $ 832,529 | 66,743 | $ 154,137 | 15,072 | $ 21,784 | 1,553 | $ 631 | $ 1,009,081 |
| Issuance of common units | 185,530 | 12,507 | — | — | — | — | — | 185,530 |
| Proceeds from exercise of unit options | 371 | 70 | — | — | — | — | — | 371 |
| Conversion of restricted units for common units, net of units withheld for taxes | (1,261) | 182 | — | — | — | — | — | (1,261) |
| Stock-based compensation | 2,539 | — | — | — | 2,512 | — | — | 5,051 |
| Distributions | (26,067) | — | — | 375 | (1,643) | 8 | — | (27,710) |
| Net income (loss) | (11,787) | — | 7,079 | — | (1,244) | — | — | (5,952) |
| Hedging gains or losses reclassified to earnings | — | — | — | — | — | — | (259) | (259) |
| Adjustment in fair value of derivatives | — | — | — | — | — | — | 132 | 132 |
| Balance, March 31, 2013 | $ 981,854 | 79,502 | $ 161,216 | 15,447 | $ 21,409 | 1,561 | $ 504 | $ 1,164,983 |

See accompanying notes to condensed consolidated financial statements.



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## CROSSTEX ENERGY, L.P.

### Consolidated Statements of Cash Flows

| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| | (Unaudited) (In thousands) | |
| Cash flows from operating activities: | | |
| Net income (loss) | $ (5,952) | $ 2,941 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | |
| Depreciation and amortization | 33,726 | 32,178 |
| (Gain) loss on sale of property | 11 | (98) |
| Deferred tax benefit | (62) | (125) |

| | | |
|---|---|---|
| Non-cash stock-based compensation | 5,051 | 2,498 |
| Non-cash portion of derivatives (gain) loss | (643) | 1,143 |
| Amortization of debt issue costs | 1,510 | 1,247 |
| Amortization of discount on notes | 474 | 474 |
| Distribution of earnings from limited liability company | 3,328 | — |
| Changes in assets and liabilities: | | |
| Accounts receivable, accrued revenue and other | 11,583 | 34,821 |
| Natural gas and natural gas liquids, prepaid expenses and other | (2,412) | (5,817) |
| Accounts payable, accrued gas and crude oil purchases and other accrued liabilities | (37,109) | (57,881) |
| Net cash provided by operating activities | 9,505 | 11,381 |
| Cash flows from investing activities: | | |
| Additions to property and equipment | (110,233) | (36,269) |
| Proceeds from sale of property | 18,005 | 121 |
| Investment in limited liability company | (12,980) | (4,860) |
| Distribution from limited liability company in excess of earnings | 1,185 | — |
| Net cash used in investing activities | (104,023) | (41,008) |
| Cash flows from financing activities: | | |
| Proceeds from borrowings | 55,500 | 169,000 |
| Payments on borrowings | (114,500) | (115,000) |
| Payments on capital lease obligations | (801) | (762) |
| Decrease in drafts payable | (1,156) | (2,651) |
| Debt refinancing costs | (1,537) | (1,240) |
| Conversion of restricted units, net of units withheld for taxes | (1,261) | (980) |
| Issuance of common units | 185,530 | — |
| Distribution to partners | (27,710) | (22,511) |
| Proceeds from exercise of unit options | 371 | 178 |
| Contributions from general partner | — | 80 |
| Net cash provided by financing activities | 94,436 | 26,114 |
| Net decrease in cash and cash equivalents | (82) | (3,513) |
| Cash and cash equivalents, beginning of period | 124 | 24,143 |
| Cash and cash equivalents, end of period | $ 42 | $ 20,630 |
| Cash paid for interest | $ 33,730 | $ 34,183 |
| Cash paid for income taxes | $ 70 | $ — |

See accompanying notes to condensed consolidated financial statements.





**CROSSTEX ENERGY, L.P.**

**Notes to Condensed Consolidated Financial Statements**

**March 31, 2013**
**(Unaudited)**

**(1) General**

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

Crosstex Energy, L.P., a Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, processing, transmission and marketing to producers of natural gas, NGLs and crude oil. We also provide crude oil, condensate and brine services to producers. We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee arrangements. In addition, we purchase natural gas from producers not connected to our gathering systems for resale and sell natural gas on behalf of producers for a fee. We provide a variety of crude services throughout the Ohio River Valley (ORV) which include crude oil gathering via pipelines and trucks and oilfield brine disposal. We also have crude oil terminal facilities in south Louisiana that provide access for crude oil producers to the premium markets in this area.

Crosstex Energy GP, LLC (the "General Partner") is the general partner of the Partnership. Crosstex Energy GP, LLC is a direct, wholly-owned subsidiary of Crosstex Energy, Inc. ("CEI").

***(a) Basis of Presentation***

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, 2012.

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) Comprehensive Income (Loss)***

*Accumulated Other Comprehensive Income Reclassifications.* In February 2013, the FASB issued ASU 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income* ("ASU 2013-02"). ASU 2013-02 requires disclosure of amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required to be reclassified to net income in its entirety in the same reporting period. For amounts not reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures that provide additional detail about those amounts. For the three months ended March 31, 2013 and 2012, we reclassified cash flow hedge (gains)/losses in the amounts of ($0.3) million and $0.1 million, respectively, included in other comprehensive income to revenues on the condensed consolidated statement of operations.





**(2) Acquisition**

On July 2, 2012, the Partnership, through a wholly-owned subsidiary, acquired all of the issued and outstanding common stock of Clearfield Energy, Inc. and Clearfield Energy's wholly owned subsidiaries (collectively, "Clearfield"). Clearfield's business included crude oil pipelines, a barge loading terminal on the Ohio River, a rail loading terminal on the Ohio Central Railroad network, a trucking fleet and brine disposal wells. All of these assets are included in the Partnership's ORV segment.

The Partnership paid approximately $215.0 million in cash (before working capital and certain purchase price adjustments) for the acquisition. The preliminary purchase price adjustment for the fair value of assets acquired and liabilities assumed at the acquisition date are pending finalization of closing adjustments.

*Pro Forma Information*

The following unaudited pro forma condensed financial data for the three months ended March 31, 2012 gives effect to the Clearfield acquisition as if it had occurred on January 1, 2011. The unaudited pro forma condensed financial information has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the transactions taken place on the dates indicated and is not intended to be a projection of future results.

| | Three Months Ended March 31, 2012 |
|---|---|
| Pro forma total revenues | $ 438,369 |
| Pro forma net income | $ 2,033 |
| Pro forma net income attributable to Crosstex Energy, L.P. | $ 2,071 |
| Pro forma net loss per common unit: | |
| Basic and Diluted | $ (0.04) |

**(3) Long-Term Debt**

As of March 31, 2013 and December 31, 2012, long-term debt consisted of the following (in thousands):

| | March 31, 2013 | December 31, 2012 |
|---|---|---|
| Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at March 31, 2013 and December 31, 2012 was 3.3% and 4.3%, respectively | $ 12,000 | $ 71,000 |
| Senior unsecured notes (due 2018), net of discount of $9.2 million and $9.7 million, respectively, which bear interest at the rate of 8.875% | 715,780 | 715,305 |
| Senior unsecured notes (due 2022), which bear interest at the rate of 7.125% | 250,000 | 250,000 |
| Debt classified as long-term | $ 977,780 | $ 1,036,305 |

*Credit Facility.* As of March 31, 2013, there was $57.1 million in outstanding letters of credit and $12.0 million borrowed under the Partnership's bank credit facility, leaving approximately $565.9 million available for future borrowing based on the borrowing capacity of $635.0 million. However, the financial covenants in the amended credit facility limit the amount of funds that we can borrow. As of March 31, 2013, based on our maximum permitted consolidated leverage ratio (as defined in the amended credit facility), we could borrow approximately $377.3 million of additional funds.

In January 2013, the Partnership amended the credit facility to, among other things, (i) decrease the minimum consolidated interest coverage ratio (as defined in the amended credit agreement, being generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) to 2.25 to 1.0 for the fiscal quarters ending September 30, 2013 and December 31, 2013, with a minimum ratio of 2.50 to 1.0 for each fiscal quarter ending thereafter, (ii) increase the maximum permitted consolidated leverage ratio (as defined in the amended credit agreement, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) to 5.50 to 1.0 for each fiscal quarter ending on or prior to December 31, 2013, with a maximum ratio





of 5.25 to 1.0 for each fiscal quarter ending thereafter, and (iii) eliminate the existing and any future step-up in the maximum permitted consolidated leverage ratio for acquisitions.

The credit facility is guaranteed by substantially all of our subsidiaries and is 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. We may prepay all loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The 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 credit facility.

All other material terms of the credit facility are described in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Indebtedness" in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012. The Partnership expects to be in compliance with all credit facility covenants for at least the next twelve months.

*Non-Guarantors.* All senior unsecured notes are jointly and severally guaranteed by each of the Partnership's current material subsidiaries (the "Guarantors"), with the exception of its regulated Louisiana subsidiaries (which may only guarantee up to $500.0 million of the Partnership's debt) 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). Guarantors may not sell or otherwise dispose of all or substantially all of their properties or assets, or consolidate with or merge into another company if such a sale would cause a default under the terms of 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 for the three months ended March 31, 2013 and 2012 are disclosed below in accordance with Rule 3-10 of Regulation S-X. Comprehensive income (loss) is not included in the condensed consolidating statements of operations of the guarantors and non-guarantors for the three months ended March 31, 2013 and 2012 as these amounts are not considered material.

**Condensed Consolidating Balance Sheets**
**March 31, 2013**

| | Guarantors | Non-Guarantors | Elimination | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| **ASSETS** | | | | |
| Total current assets | $ 213,784 | $ 12,173 | $ — | $ 225,957 |
| Property, plant and equipment, net | 1,367,931 | 198,764 | — | 1,566,695 |
| Total other assets | 690,992 | — | — | 690,992 |
| Total assets | $ 2,272,707 | $ 210,937 | $ — | $ 2,483,644 |
| **LIABILITIES & PARTNERS' CAPITAL** | | | | |
| Total current liabilities | $ 233,455 | $ 6,493 | $ — | $ 239,948 |
| Long-term debt | 977,780 | — | — | 977,780 |
| Other long-term liabilities | 100,933 | — | — | 100,933 |
| Partners' capital | 960,539 | 204,444 | — | 1,164,983 |
| Total liabilities & partners' capital | $ 2,272,707 | $ 210,937 | $ — | $ 2,483,644 |

**December 31, 2012**

| | Guarantors | Non-Guarantors | Elimination | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| **ASSETS** | | | | |
| Total current assets | $ 246,165 | $ 11,055 | $ — | $ 257,220 |
| Property, plant and equipment, net | 1,276,097 | 195,151 | — | 1,471,248 |
| Total other assets | 694,121 | — | — | 694,121 |
| Total assets | $ 2,216,383 | $ 206,206 | $ — | $ 2,422,589 |
| **LIABILITIES & PARTNERS' CAPITAL** | | | | |
| Total current liabilities | $ 273,151 | $ 2,392 | $ — | $ 275,543 |
| Long-term debt | 1,036,305 | — | — | 1,036,305 |
| Other long-term liabilities | 101,660 | — | — | 101,660 |
| Partners' capital | 805,267 | 203,814 | — | 1,009,081 |
| Total liabilities & partners' capital | $ 2,216,383 | $ 206,206 | $ — | $ 2,422,589 |



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**Condensed Consolidating Statements of Operations**
**For the Three Months Ended March 31, 2013**

| | Guarantors | Non-Guarantors | Elimination | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| Total revenues | $ 433,076 | $ 19,279 | $ (6,666) | $ 445,689 |
| Total operating costs and expenses | (429,759) | (7,710) | 6,666 | (430,803) |
| Operating income | 3,317 | 11,569 | — | 14,886 |
| Interest expense, net | (20,273) | 2 | — | (20,271) |
| Other income | 142 | — | — | 142 |
| Income (loss) before non-controlling interest and income taxes | (16,814) | 11,571 | — | (5,243) |
| Income tax provision | (709) | — | — | (709) |
| Net income (loss) attributable to Crosstex Energy, L.P. | $ (17,523) | $ 11,571 | $ — | $ (5,952) |

**For the Three Months Ended March 31, 2012**

| | Guarantors | Non-Guarantors | Elimination | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| Total revenues | $ 357,153 | $ 22,277 | $ (7,721) | $ 371,709 |
| Total operating costs and expenses | (347,587) | (9,108) | 7,721 | (348,974) |
| Operating income | 9,566 | 13,169 | — | 22,735 |
| Interest expense, net | (19,373) | (9) | — | (19,382) |
| Other expense | 12 | — | — | 12 |
| Income (loss) before non-controlling interest and income taxes | (9,795) | 13,160 | — | 3,365 |
| Income tax provision | (420) | (4) | — | (424) |
| Net loss attributable to non-controlling interest | — | (38) | — | (38) |

| | Guarantors | Non-Guarantors | Elimination | Consolidated |
|---|---|---|---|---|
| Net income (loss) income attributable to Crosstex Energy, L.P. | $ (10,215) | $ 13,194 | $ — | $ 2,979 |

**Condensed Consolidating Statements of Cash Flow**
**For the Three Months Ended March 31, 2013**

| | Guarantors | Non-Guarantors | Elimination | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| Net cash flows provided by (used in) operating activities | $ (4,772) | $ 14,277 | $ — | $ 9,505 |
| Net cash flows used in investing activities | $ (100,687) | $ (3,336) | $ — | $ (104,023) |
| Net cash flows provided by (used in) financing activities | $ 94,436 | $ (10,941) | $ 10,941 | $ 94,436 |





**CROSSTEX ENERGY, L.P.**

**Notes to Condensed Consolidated Financial Statements-(Continued)**

**For the Three Months Ended March 31, 2012**

| | Guarantors | Non-Guarantors | Elimination | Consolidated |
|---|---|---|---|---|
| | | (In thousands) | | |
| Net cash flows provided by (used in) operating activities | $ (1,073) | $ 12,454 | $ — | $ 11,381 |
| Net cash flows used in investing activities | $ (40,647) | $ (361) | $ — | $ (41,008) |
| Net cash flows provided by (used in) financing activities | $ 26,114 | $ (12,040) | $ 12,040 | $ 26,114 |

**(4) Other Long-term Liabilities**

The Partnership has the following assets under capital leases as of March 31, 2013 (in thousands):

| | |
|---|---|
| Compressor equipment | $ 37,199 |
| Less: Accumulated amortization | (14,676) |
| Net assets under capital leases | $ 22,523 |

The following are the minimum lease payments to be made in each of the following years indicated for the capital leases in effect as of March 31, 2013 (in thousands):

| Fiscal Year | |
|---|---|
| 2013 | $ 3,437 |
| 2014 | 4,582 |
| 2015 | 4,582 |
| 2016 | 4,582 |
| 2017 | 6,910 |
| Thereafter | 5,189 |
| Less: Interest | (4,827) |
| Net minimum lease payments under capital lease | 24,455 |
| Less: Current portion of net minimum lease payments | (4,448) |
| Long-term portion of net minimum lease payments | $ 20,007 |

**(5) Partners' Capital**

***(a) Issuance of Common Units***

On January 14, 2013, the Partnership issued 8,625,000 common units representing limited partner interests in the Partnership at a public offering price of $15.15 per common unit for net proceeds of $125.4 million. Concurrently with the public offering, the Partnership issued 2,700,000 common units representing limited partner interests in the Partnership at an offering price of $14.55 per unit for net proceeds of $39.2 million. The net proceeds from both common unit offerings were used for capital expenditures, to repay bank borrowings and for general partnership purposes. The General Partner did not exercise its option to make a general partner contribution to maintain its then current general partner percentage interest in connection with these offerings.

In March 2013, we entered into an Equity Distribution Agreement (the "EDA") with BMO Capital Markets Corp. ("BMOCM"). Pursuant to the terms of the EDA, we may from time to time through BMOCM, as our sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0 million. Sales of such common units will be made by means of ordinary brokers' transactions through the facilities of the Nasdaq Global Select Market LLC at market prices, in block transactions or as otherwise agreed by BMOCM and us. Under the terms of the EDA, we may sell common units from time to time to BMOCM as principal for its own account at a price to be agreed upon at the time of sale. For any such sales, we will enter into a separate terms agreement with BMOCM.





**CROSSTEX ENERGY, L.P.**

**Notes to Condensed Consolidated Financial Statements-(Continued)**

Through March 31, 2013, we sold an aggregate of 1.2 million common units under the EDA, generating proceeds of approximately $20.9 million (net of approximately $0.3 million of commissions to BMOCM). We used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness.

***(b) Distributions***

Unless restricted by the terms of the Partnership's credit facility and/or the indentures governing the Partnership's 8.875% senior notes due 2018 (the "2018 Notes") or the Partnership's 7.125% senior notes due 2022 (the "2022 Notes" and, together with the 2018 Notes, "all senior unsecured notes"), 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.

The Partnership's fourth quarter 2012 distributions on its common and preferred units of $0.33 per unit were paid on February 14, 2013 with the preferred units paid-in-kind ("PIK") through the issuance of 0.4 million preferred units. The Partnership declared its first quarter 2013 distribution on its common and preferred units of $0.33 per unit to be paid on May 13, 2013.

***(c) Earnings per Unit and Dilution Computations***

The Partnership had common units and preferred units outstanding during the three months ended March 31, 2013 and March 31, 2012.

The preferred units are entitled to a quarterly distribution paid-in-kind in the form of additional preferred units 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 fair value of the PIK preferred unit distributions is based on the market value of common units on the record date of such distributions.

As required under FASB ASC 260-10-45-61A, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, for earnings per unit calculations. The following table reflects the computation of basic earnings per limited partner units for the periods presented (in thousands except per unit amounts):

| | Three Months Ended March 31, 2013 | 2012 |
|---|---|---|
| Limited partners' interest in net loss | $ (11,787) | $ (1,803) |
| Distributed earnings allocated to: | | |
| Common units (1)(2) | $ 25,359 | $ 16,783 |
| Unvested restricted units (1)(2) | 387 | 339 |
| Total distributed earnings | $ 25,746 | $ 17,122 |
| Undistributed loss allocated to: | | |
| Common units | $ (36,969) | $ (18,551) |
| Unvested restricted units | (564) | (374) |
| Total undistributed loss | $ (37,533) | $ (18,925) |
| Net loss allocated to: | | |
| Common units | $ (11,610) | $ (1,768) |
| Unvested restricted units | (177) | (35) |
| Total limited partners' interest in net loss | $ (11,787) | $ (1,803) |
| Basic and diluted net loss per unit: | | |
| Basic and diluted common unit | $ (0.15) | $ (0.03) |

(1) Three months ended March 31, 2013 represents a declared distribution of $0.33 per unit payable on May 13, 2013.





(2) Three months ended March 31, 2012 represents a declared distribution of $0.33 per unit paid on May 15, 2012.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the three months ended March 31, 2013 and 2012 (in thousands):

| | Three Months Ended March 31, 2013 | 2012 |
|---|---|---|
| Basic and diluted weighted average units outstanding: | | |
| Weighted average limited partner common units outstanding | 76,849 | 50,857 |

All common unit equivalents were antidilutive in the three months ended March 31, 2013 and March 31, 2012 because the limited partners were allocated net losses in these periods.

The general partner is entitled to a distribution in relation to its percentage interest with respect to all distributions made to common unitholders. If the distributions are in excess of $0.2125 per unit, distributions are made to the general partner in accordance with its current percentage interest with the remainder to the common and preferred unitholders, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved.

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 the percentage interest 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 the general partner's percentage interest 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.

Under the quarterly incentive distribution provisions, generally the Partnership's general partner is entitled to 13.0% of amounts the Partnership distributes in excess of $0.25 per unit, 23.0% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48.0% of amounts the Partnership distributes in excess of $0.375 per unit. The net income (loss) allocated to the general partner is as follows (in thousands):

| | Three Months Ended March 31, 2013 | 2012 |
|---|---|---|
| Income allocation for incentive distributions | $ 1,404 | $ 979 |
| Stock-based compensation attributable to CEI's restricted shares | (2,470) | (1,133) |

| | | |
|---|---|---|
| General partner interest in net income (loss) | (178) | 83 |
| General partner share of net loss | $ (1,244) | $ (71) |

**(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 condensed consolidated financial statements with respect to these plans are as follows (in thousands):





| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| Cost of share-based compensation charged to general and administrative expense | $ 4,492 | $ 2,174 |
| Cost of share-based compensation charged to operating expense | 559 | 324 |
| Total amount charged to income | $ 5,051 | $ 2,498 |

***(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 three months ended March 31, 2013 is provided below:

| Crosstex Energy, L.P. Restricted Units: | Three Months Ended March 31, 2013 Number of Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested, beginning of period | 1,003,159 | $ 13.31 |
| Granted | 526,502 | 15.89 |
| Vested* | (264,140) | 8.70 |
| Forfeited | (20,945) | 15.37 |
| Non-vested, end of period | 1,244,576 | $ 15.35 |
| Aggregate intrinsic value, end of period (in thousands) | $ 22,900 | |

* Vested units include 82,348 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued restricted units in 2013 to officers and other employees. These restricted units typically vest at the end of three years and are included in the restricted units outstanding and the current share-based compensation cost calculations at March 31, 2013. In March 2013, the Partnership issued 57,897 restricted units with a fair value of $1.0 million to officers and certain employees as bonus payments for 2012, which vested immediately and are included in the restricted units granted and vested line items above.

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 months ended March 31, 2013 and 2012 are provided below (in thousands):

| Crosstex Energy, L.P. Restricted Units: | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| Aggregate intrinsic value of units vested | $ 4,024 | $ 3,511 |
| Fair value of units vested | $ 2,299 | $ 1,327 |

As of March 31, 2013, there was $10.6 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.7 years.

***(c) Unit Options***

A summary of the unit option activity for the three months ended March 31, 2013 is provided below:





| Crosstex Energy, L.P. Unit Options: | Three Months Ended March 31, 2013 Number of Units | Weighted Average Exercise Price |
|---|---|---|

| | | |
|---|---|---|
| Outstanding, beginning of period | 349,018 | $ 7.25 |
| Exercised | (70,278) | 5.70 |
| Forfeited | (2,681) | 26.75 |
| Outstanding, end of period | 276,059 | $ 7.46 |
| Options exercisable at end of period | 276,059 | |
| Weighted average contractual term (years) end of period: | | |
| Options outstanding | 5.9 | |
| Options exercisable | 5.9 | |
| Aggregate intrinsic value end of period (in thousands): | | |
| Options outstanding | $ 3,345 | |
| Options exercisable | $ 3,345 | |

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 exercised (value per Black-Scholes-Merton option pricing model at date of grant) during the three months ended March 31, 2013 and March 31, 2012 are provided below (in thousands):

| | Three Months Ended March 31, | |
|---|---|---|
| **Crosstex Energy, L.P. Unit Options:** | **2013** | **2012** |
| Intrinsic value of unit options exercised | $ 814 | $ 411 |
| Fair value of unit options vested | $ 254 | $ 277 |

As of March 31, 2013, all options were vested and fully expensed.

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

CEI's restricted shares are valued 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 three months ended March 31, 2013 is provided below:

| | Three Months Ended March 31, 2013 | |
|---|---|---|
| **Crosstex Energy, Inc. Restricted Shares:** | **Number of Shares** | **Weighted Average Grant-Date Fair Value** |
| Non-vested, beginning of period | 1,329,162 | $ 9.75 |
| Granted | 533,482 | 15.63 |
| Vested* | (264,887) | 7.43 |
| Forfeited | (25,318) | 12.27 |
| Non-vested, end of period | 1,572,439 | $ 12.09 |
| Aggregate intrinsic value, end of period (in thousands) | $ 30,285 | |

* Vested shares include 79,021 shares withheld for payroll taxes paid on behalf of employees.

CEI issued restricted shares in 2013 to officers and other employees. These restricted shares typically vest at the end of three years and are included in restricted shares outstanding and the current share-based compensation cost calculations at March 31, 2013. In March 2013, CEI issued 60,018 restricted shares with a fair value of $1.0 million to officers and certain employees as bonus payments for 2012, which vested immediately and are included in restricted shares granted and vested in the above line items.

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 months ended March 31, 2013 and March 31, 2012 are provided below (in thousands):





| | Three Months Ended March 31, | |
|---|---|---|
| **Crosstex Energy, Inc. Restricted Shares:** | **2013** | **2012** |
| Aggregate intrinsic value of shares vested | $ 3,990 | $ 2,736 |
| Fair value of shares vested | $ 1,967 | $ 1,006 |

As of March 31, 2013, there was $11.1 million of unrecognized compensation costs related to non-vested CEI restricted shares. The cost is expected to be recognized over a weighted average period of 1.6 years.

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

CEI stock options have not been granted to officers or employees of the Partnership since 2005. There are 37,500 CEI stock options vested and exercisable at March 31, 2013.

**(7) Derivatives**

***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," "storage swaps," "basis swaps," "processing margin swaps," "liquids swaps" and "put options." 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. Storage swap transactions protect against changes in the value of products that the Partnership has stored to serve various operational requirements (gas) or has in inventory due to short term constraints in moving the product to market (liquids). 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. Liquids financial swaps are used to hedge price risk on percent of liquids (POL) contracts. Put options are purchased to hedge against declines in pricing and as such represent options, not obligations, to sell the related underlying volumes at a fixed price.

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

| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| Change in fair value of derivatives that do not qualify for hedge accounting | $ (631) | $ 1,181 |
| Realized losses on derivatives | 1,115 | 1,026 |
| Ineffective portion of derivatives qualifying for hedge accounting | (12) | (38) |
| Loss on derivatives | $ 472 | $ 2,169 |

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

| | March 31, 2013 | December 31, 2012 |
|---|---|---|
| Fair value of derivative assets — current, designated | $ 551 | $ 724 |
| Fair value of derivative assets — current, non-designated | 2,147 | 2,510 |
| Fair value of derivative assets — long term, designated | 9 | — |
| Fair value of derivative liabilities — current, designated | (43) | (105) |
| Fair value of derivative liabilities — current, non-designated | (212) | (1,205) |
| Fair value of derivative liabilities — long term, designated | (12) | — |
| Net fair value of derivatives | $ 2,440 | $ 1,924 |





Set forth below is the summarized notional volumes and fair value of all instruments held for price risk management purposes and related physical offsets as of March 31, 2013 (all gas volumes are expressed in MMBtus and liquids volumes are expressed in gallons). The remaining terms of the contracts extend no later than December 2014. 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.

| Transaction Type | March 31, 2013 Volume | March 31, 2013 Fair Value |
|---|---|---|
| | (In thousands) | |
| *Cash Flow Hedges:** | | |
| Liquids swaps (short contracts) | (7,076) | $ 505 |
| Total swaps designated as cash flow hedges | | $ 505 |
| | | |
| *Mark to Market Derivatives:** | | |
| Swing swaps (short contracts) | (1,014) | $ — |
| Physical offsets to swing swap transactions (long contracts) | 1,014 | — |
| | | |
| Basis swaps (long contracts) | 450 | — |
| Physical offsets to basis swap transactions (short contracts) | (450) | 1,585 |
| Basis swaps (short contracts) | (450) | 8 |
| Physical offsets to basis swap transactions (long contracts) | 450 | (1,745) |
| | | |
| Processing margin hedges — liquids (short contracts) | (4,483) | 1,059 |
| Processing margin hedges — gas (long contracts) | 523 | 272 |
| | | |
| Liquids swaps - non-designated (short contracts) | (3,407) | 792 |
| | | |
| Storage swap transactions — gas (short contracts) | (100) | (35) |
| Storage swap transactions — liquids inventory (short contracts) | (840) | (1) |
| Total mark to market derivatives | | $ 1,935 |

* All are gas contracts, volume in MMBtus, except for liquids swaps (designated or non-designated) and processing margin hedges - liquids (volume in gallons).

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 (ISDAs) with its counterparties. If the Partnership's counterparties failed to perform under existing swap contracts entered into under these ISDAs, the Partnership's maximum loss as of March 31, 2013 of $2.7 million would be reduced to $2.6 million due to the offsetting of gross fair value payables against gross fair value receivables as allowed by the ISDAs.

***Impact of Cash Flow Hedges***

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





| | Three Months Ended March 31, | |
|---|---|---|
| **Increase (Decrease) in Midstream Revenue** | **2013** | **2012** |
| Liquids realized gain (loss) included in Midstream revenue | $ 280 | $ (12) |

*Natural Gas*

As of March 31, 2013, the Partnership had no balances in accumulated other comprehensive income related to natural gas.

*Liquids*

As of March 31, 2013, an unrealized derivative fair value net gain of $0.5 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income, all of which is expected to be reclassified into earnings through March 2014. 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 is not reflected in the above table.

***Derivatives Other Than Cash Flow Hedges***

Assets and liabilities related to third party derivative contracts, swing swaps, basis swaps, storage swaps, processing margin swaps and liquids 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 condensed 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** |
| March 31, 2013 | $ 1,935 | $ — | $ — | $ 1,935 |

**(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):

| | March 31, 2013 Level 2 | December 31, 2012 Level 2 |
|---|---|---|
| Commodity Swaps* | $ 2,440 | $ 1,924 |
| Total | $ 2,440 | $ 1,924 |





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

***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):

| March 31, 2013 | December 31, 2012 |
|---|---|

| | Carrying Value | Fair Value | Carrying Value | Fair Value |
|---|---|---|---|---|
| Long-term debt | $ 977,780 | $ 1,064,938 | $ 1,036,305 | $ 1,118,875 |
| Obligations under capital lease | $ 24,455 | $ 26,683 | $ 25,257 | $ 27,667 |

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 $12.0 million in borrowings under its revolving credit facility included in long-term debt as of March 31, 2013 and $71.0 million at December 31, 2012. As borrowings under the credit facility accrue interest under floating interest rate structures, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of March 31, 2013 and December 31, 2012, the Partnership also had borrowings totaling $715.8 million and $715.3 million, net of discount, respectively, under the 2018 Notes with a fixed rate of 8.875% and borrowings of $250.0 million under the 2022 Notes with a fixed rate of 7.125%. The fair value of all senior unsecured notes as of March 31, 2013 and December 31, 2012 was based on Level 1 inputs from third-party market quotations. The fair value of obligations under capital leases was calculated using Level 2 inputs from third-party banks.

**(9) Commitments and Contingencies**

***(a) Employment and Severance Agreements***

Certain members of management of the Partnership are parties to employment and/or severance agreements with the general partner. The employment and severance agreements provide those managers with severance payments in certain circumstances and, in the case of employment agreements, 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. To date, 23 of the 25 sites requiring remediation have been completed and have received a "No Further Action" status from the Louisiana Department of Environmental Quality. The remaining two sites continuing with remediation efforts are expected to reach closure in 2013. 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.

***(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.





At times, the Partnership's subsidiaries acquire pipeline easements and other property rights by exercising rights of eminent domain and common carrier. 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 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.

The Partnership (or its subsidiaries) is defending 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, processing and treating facilities in urban and occupied rural areas. In January 2012, a plaintiff in one of these lawsuits was awarded a judgment of $2.0 million. The Partnership has appealed the matter and has posted a bond to secure the judgment pending its resolution. The Partnership has accrued $2.0 million related to this matter. 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.

**(10) Segment Information**

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 and in the Permian Basin in west Texas (NTX), the pipelines and processing plants located in Louisiana (LIG), the south Louisiana processing and NGL assets (PNGL) and rail, truck, pipeline, and barge facilities in the Ohio River Valley (ORV). Operating activity for intersegment eliminations is shown in the corporate segment. The Partnership's sales are derived from external domestic customers.

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 primarily of property and equipment, including software, for general corporate support, working capital, debt financing costs and its investment in HEP.

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

| | LIG | NTX | PNGL | ORV | Corporate | Totals |
|---|---|---|---|---|---|---|
| | | | (In thousands) | | | |
| **Three Months Ended March 31, 2013:** | | | | | | |
| Sales to external customers | $ 133,057 | $ 73,450 | $ 183,923 | $ 55,259 | $ — | $ 445,689 |
| Sales to affiliates | $ 29,786 | $ 16,363 | $ 16,427 | $ — | $ (62,576) | $ — |
| Purchased gas, NGLs and crude oil | $ (140,633) | $ (46,118) | $ (175,783) | $ (41,064) | $ 62,576 | $ (341,022) |
| Operating expenses | $ (7,661) | $ (14,172) | $ (7,218) | $ (8,285) | $ — | $ (37,336) |
| Segment profit | $ 14,549 | $ 29,523 | $ 17,349 | $ 5,910 | $ — | $ 67,331 |
| Gain (loss) on derivatives | $ 373 | $ (775) | $ (70) | $ — | $ — | $ (472) |
| Depreciation, amortization and impairments | $ (3,120) | $ (19,791) | $ (7,975) | $ (2,342) | $ (498) | $ (33,726) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Capital expenditures | $ 8,232 | $ 5,023 | $ 96,166 | $ 4,195 | $ 4,954 | $ 118,570 |
| Identifiable assets | $ 285,379 | $ 1,034,580 | $ 708,989 | $ 302,662 | $ 152,034 | $ 2,483,644 |
| **Three Months Ended March 31, 2012:** | | | | | | |
| Sales to external customers | $ 146,697 | $ 64,681 | $ 160,331 | $ — | $ — | $ 371,709 |
| Sales to affiliates | 72,810 | 31,484 | 45,545 | — | (149,839) | — |
| Purchased gas, NGLs and crude oil | (189,220) | (50,021) | (182,554) | — | 149,839 | (271,956) |
| Operating expenses | (7,936) | (13,151) | (6,719) | — | — | (27,806) |
| Segment profit | $ 22,351 | $ 32,993 | $ 16,603 | $ — | $ — | $ 71,947 |
| Gain (loss) on derivatives | $ 102 | $ (2,263) | $ (8) | $ — | $ — | $ (2,169) |
| Depreciation, amortization and impairments | $ (3,153) | $ (20,433) | $ (7,959) | $ — | $ (633) | $ (32,178) |
| Capital expenditures | $ 8 | $ 13,156 | $ 15,662 | $ — | $ 454 | $ 29,280 |
| Identifiable assets | $ 286,911 | $ 1,092,530 | $ 463,249 | $ — | $ 80,760 | $ 1,923,450 |



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**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 condensed consolidated statements of operations (in thousands):

| | Three Months Ended March 31, 2013 | 2012 |
|---|---|---|
| Segment profits | $ 67,331 | $ 71,947 |
| General and administrative expenses | (18,236) | (14,963) |
| Loss on derivatives | (472) | (2,169) |
| Gain (loss) on sale of property | (11) | 98 |
| Depreciation, amortization and impairments | (33,726) | (32,178) |
| Operating income | $ 14,886 | $ 22,735 |



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

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

**Overview**

We are a Delaware limited partnership formed on July 12, 2002. We primarily focus on providing midstream energy services, including gathering, processing, transmission and marketing to producers of natural gas, natural gas liquids (NGLs) and crude oil. We also provide crude oil, condensate and brine services to producers. Our midstream energy asset network includes approximately 3,500 miles of pipelines, ten natural gas processing plants, four fractionators, 3.1 million barrels of NGL cavern storage, rail terminals, barge terminals, truck terminals and a fleet of approximately 100 trucks. We manage and report our activities primarily according to geography. We have five reportable segments: (1) South Louisiana processing, crude and NGL, or PNGL, which includes our processing and NGL assets in South Louisiana; (2) Louisiana, or LIG, which includes our pipelines and processing plants located in Louisiana; (3) North Texas, or NTX, which includes our activities in the Barnett Shale and the Permian Basin; (4) Ohio River Valley, or ORV, which includes our activities in the Utica and Marcellus Shales; and (5) Corporate Segment, or Corporate, which includes our equity investment in Howard Energy Partners, or HEP, in the Eagle Ford Shale and our general partnership property and expenses.

We manage our operations by focusing on gross operating margin because our business is generally to purchase and resell natural gas, NGLs and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil for a fee. In addition, we earn a volume based fee for brine disposal services. We define gross operating margin as operating revenue minus cost of purchased gas, NGLs and crude oil. Gross operating margin is a non-GAAP financial measure and is explained in greater detail under "Non-GAAP Financial Measures" below.

Our gross operating margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, the volumes of NGLs handled at our fractionation facilities, the volumes of crude oil handled at our crude terminals, the volumes of crude oil gathered, transported, purchased and sold and the volume of brine disposed. We generate revenues from seven 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;
- providing compression services;
- purchasing and reselling crude oil and condensate;
- providing crude oil transportation and terminal services; and
- providing brine disposal 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. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. 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, on occasion we have entered into 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.





One contract (the "Delivery Contract") has a term to 2019 that obligates us to supply approximately 150,000 MMBtu/d of gas. At the time that we entered into the Delivery Contract in 2008, we had dedicated supply sources in the Barnett Shale that exceeded the delivery obligations under the Delivery Contract. Our agreements with these suppliers generally provided that the purchase price for the gas was equal to a portion of our sales price for such gas less certain fees and costs. Accordingly, we were initially able to generate a positive margin under the Delivery Contract. However, since entering into the Delivery Contract, there has been both (1) a reduction in the gas available under our supply contracts and (2) the discovery of other shale reserves, most notably the Haynesville and the Marcellus Shales, which has increased the supplies available to east coast markets and reduced the basis spread between north Texas-area production and the market indices used in the Delivery Contract. Due to these factors, we have had to purchase a portion of the gas necessary to fulfill our obligations under the Delivery Contract at market prices, resulting in negative margins under the Delivery Contract.

We have recorded a loss of approximately $4.2 million during the three months ended March 31, 2013 on the Delivery Contract. We currently expect that we will record an additional loss of approximately $16.0 million to $20.0 million on the Delivery Contract for the remainder of the year ending December 31, 2013. This estimate is based on forward prices, basis spreads and other market assumptions as of March 31, 2013. These assumptions are subject to change if market conditions change during the remainder of 2013, and actual results under the Delivery Contract in 2013 could be substantially different from our current estimates, which may result in a greater loss than currently estimated.

We generally gather or transport crude oil owned by others by rail, truck, pipeline and barge facilities for a fee, orwe buy crude oil from a producer at a fixed discount to a market index, then transport and resell the crude oil at the market index. We execute all purchases and sales substantially concurrently, thereby establishing the basis for the margin we will receive for each crude oil transaction. Additionally,we provide crude oil, condensate and brine services on a volume basis.

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 higher liquids prices. Under fixed-fee based contracts our gross operating 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, property insurance, property taxes, repair and maintenance expenses, contract services 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, liquids or crude oil moved through or by 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, fees, services and other transaction costs related to acquisitions, 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**

*Cajun-Sibon Phases I and II.* In Louisiana, we are transforming our business that has been historically focused on processing offshore natural gas to a business that is focused on NGLs with additional opportunities for growth from new onshore supplies of NGLs. The Louisiana petrochemical market has historically relied on liquids from offshore production; however, the decrease in offshore production and increase in onshore rich gas production have changed the market structure. Cajun-Sibon Phases I and II will work to bridge the gap between supply, which aggregates in the Mont Belvieu area, and demand, located in the Mississippi River corridor of Louisiana, thereby building a strategic NGL position in this region.

We began this transformation by restarting our Eunice fractionator during 2011 at a rate of 15,000 barrels per day ("Bbls/d") of NGLs. This is a pivotal asset for Cajun-Sibon Phase I as we are expanding this facility to a rate of 55,000 Bbls/d. When Phase I of our pipeline extension project is completed, Mont Belvieu supply lines in east Texas will be connected to Eunice providing a direct link to our fractionators in south Louisiana markets. The Phase I Eunice fractionator expansion will increase our interconnected fractionation





capacity in Louisiana to approximately 97,000 Bbls/d of raw-make NGLs. The Eunice fractionator was taken out of service in March 2013 to complete the expansion work and is expected to be back in service in June 2013.

Construction is underway on the Phase I pipeline extension. The pipeline extension between Mont Belvieu and Eunice will have an initial capacity of approximately 70,000 Bbls/d for raw-make NGLs. We expect Phase I facilities, both the pipeline and the expanded fractionation facilities, will be operating by mid-2013.

Cajun-Sibon Phase II will further enhance our Louisiana NGL business with significant additions to the Cajun-Sibon Phase I NGL pipeline extension and Eunice expansion. Under Phase II we will add pumping stations on the Phase I pipeline extension to increase its NGL supply capacity from approximately 70,000 Bbls/d to approximately 120,000 Bbls/d, construct a new 100,000 Bbl/d fractionator at the Plaquemine gas processing plant site and extend the Phase I NGL pipeline from Eunice to the new Plaquemine fractionator. We expect Phase II will be in service during the second half of 2014.

*Issuance of Common Units.* On January 14, 2013, we issued 8,625,000 common units representing limited partner interests in the Partnership at a public offering price of $15.15 per common unit for net proceeds of $125.4 million. Concurrently with the public offering, we issued 2,700,000 common units representing limited partner interest in the Partnership at a price of $14.55 per unit for net proceeds of $39.2 million. The net proceeds from both common unit offerings were used for capital expenditures for currently identified projects, to repay bank borrowings and for general partnership purposes. Our general partner did not make a general partner contribution to maintain its general partner interest.

In March 2013, we entered into an Equity Distribution Agreement (the "EDA") with BMO Capital Markets Corp. ("BMOCM"). Pursuant to the terms of the EDA, we may from time to time through BMOCM, as our sales agent, sell common units representing limited partner interests having an aggregate offering price of up to $75.0

million. Sales of such common units will be made by means of ordinary brokers' transactions through the facilities of the Nasdaq Global Select Market LLC at market prices, in block transactions or as otherwise agreed by BMOCM and us. Under the terms of the EDA, we may sell common units from time to time to BMOCM as principal for its own account at a price to be agreed upon at the time of sale. For any such sales, we will enter into a separate terms agreement with BMOCM.

Through March 31, 2013, we sold an aggregate of 1.2 million common units under the EDA, generating proceeds of approximately $20.9 million (net of approximately $0.3 million of commissions to BMOCM). We used the net proceeds for general partnership purposes, including working capital, capital expenditures and repayments of indebtedness.

*Other Developments.* Howard Energy Partners ("HEP") is continuing to expand its midstream assets in the Eagle Ford shale in south Texas. We contributed an additional $13.0 million to HEP during the three months ended March 31, 2013 to fund our 30.6 percent share of HEP's expansion costs. We also received our first cash distribution of $4.4 million from HEP during the three months ended March 31, 2013. We are obligated to contribute additional funds to HEP upon one or more requests made by HEP. We expect that as HEP makes additional distributions to us and its other investors, HEP will request that we make additional capital contributions to fund its ongoing expansion efforts.

**Non-GAAP Financial Measures**

We include the following non-generally accepted accounting principles, or non-GAAP, financial measures: Adjusted earnings before interest, taxes, depreciation and amortization, or adjusted EBITDA, and gross operating margin.

We define adjusted EBITDA as net income plus interest expense, provision for income taxes, depreciation and amortization expense, impairments, stock-based compensation, (gain) loss on noncash derivatives, distribution from limited liability company and noncontrolling interest; less gain on sale of property and equity in losses of limited liability company. Adjusted EBITDA is used as a supplemental performance measure by our management and by external users of our financial statements, such as investors, commercial banks, research analysts and others, to assess:

- financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our unitholders and our general partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing methods or capital structure; and



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- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Adjusted EBITDA is one of the critical inputs into the financial covenants within our credit facility. The rates we pay for borrowings under our credit facility are determined by the ratio of our debt to adjusted EBITDA. The calculation of these ratios allows for further adjustments to adjusted EBITDA for recent material projects and acquisitions and dispositions.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted EBITDA may not be comparable to similarly titled measures of other companies because other entities may not calculate adjusted EBITDA in the same manner.

Adjusted EBITDA does not include interest expense, income taxes or depreciation and amortization expense. Because we have borrowed money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net earnings determined under GAAP, as well as adjusted EBITDA, to evaluate our overall performance.

The following table provides a reconciliation of net income (loss) to adjusted EBITDA:

| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| | (In millions) | |
| Net income (loss) attributable to Crosstex Energy, L.P. | $ (6.0) | $ 3.0 |
| Interest expense | 20.3 | 19.4 |
| Depreciation and amortization | 33.7 | 32.2 |
| Distribution from limited liability company (b) | 4.5 | — |
| (Gain) loss on sale of property | — | (0.1) |
| Stock-based compensation | 5.1 | 2.5 |
| Other (a) | 0.1 | 1.5 |
| Adjusted EBITDA | $ 57.7 | $ 58.5 |

(a) Includes financial derivatives marked-to-market; income taxes; and noncontrolling interest.

(b) Includes an add-back for the Partnership's equity in the Howard Energy Partners loss, in the amount of $0.1 million, for the three months ended March 31, 2013.

We define gross operating margin, generally, as revenues minus cost of purchased gas, NGLs and crude oil. We present gross operating margin by segment in "Results of Operations." We disclose gross operating margin in addition to total revenue because it is the primary performance measure used by our management. We believe gross operating margin is an important measure because our business is generally to purchase and resell natural gas and crude oil for a margin or to gather, process, transport or market natural gas, NGLs and crude oil for a fee. Operating expense is a separate measure used by management to evaluate operating performance of field operations. Direct labor and supervision, property insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of our operating expenses. We do not deduct operating expenses from total revenue in calculating gross operating margin because these expenses are largely independent of the volumes we transport or process and fluctuate depending on the activities performed during a specific period. As an indicator of our operating performance, gross operating margin should not be considered an alternative to, or more meaningful than, net income as determined in accordance with GAAP. Our gross operating margin may not be comparable to similarly titled measures of other companies because other entities may not calculate these amounts in the same manner.

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

**Three Months Ended**

| | March 31, | |
|---|---|---|
| | 2013 | 2012 |
| | (In millions) | |
| Total gross operating margin | $ 104.7 | $ 99.8 |
| Add (deduct): | | |
| Operating expenses | (37.3) | (27.8) |
| General and administrative expenses | (18.2) | (15.0) |
| Gain (loss) on sale of property | — | 0.1 |
| Loss on derivatives | (0.5) | (2.2) |
| Depreciation, amortization and other | (33.8) | (32.2) |
| Operating income | $ 14.9 | $ 22.7 |



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**Results of Operations**

Set forth in the table below is certain financial and operating data for the periods indicated, which includes our July 2012 acquisition of the ORV assets reflected in the three months ended March 31, 2013. We manage our operations by focusing on gross operating margin which we define as operating revenue minus cost of purchased gas, NGLs and crude oil as reflected in the table below.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2013 | 2012 |
| | (Dollars in millions) | |
| **LIG Segment** | | |
| Revenues | $ 162.8 | $ 219.5 |
| Purchased gas and NGLs | (140.6) | (189.2) |
| Total gross operating margin | $ 22.2 | $ 30.3 |
| **NTX Segment** | | |
| Revenues | $ 89.9 | $ 96.2 |
| Purchased gas and NGLs | (46.1) | (50.0) |
| Total gross operating margin | $ 43.8 | $ 46.2 |
| **PNGL Segment** | | |
| Revenues | $ 200.3 | $ 205.9 |
| Purchased gas, NGLs and crude oil | (175.8) | (182.6) |
| Total gross operating margin | $ 24.5 | $ 23.3 |
| **ORV Segment** | | |
| Revenues | $ 55.3 | — |
| Purchased crude oil | (41.1) | — |
| Total gross operating margin | $ 14.2 | — |
| **Corporate** | | |
| Revenues | $ (62.6) | $ (149.8) |
| Purchased gas and NGLs | 62.6 | 149.8 |
| Total gross operating margin | $ — | $ — |
| **Total** | | |
| Revenues | $ 445.7 | $ 371.8 |
| Purchased gas, NGLs and crude oil | (341.0) | (272.0) |
| Total gross operating margin | $ 104.7 | $ 99.8 |
| | | |
| **Midstream Volumes:** | | |
| **LIG** | | |
| Gathering and Transportation (MMBtu/d) | 595,000 | 900,000 |
| Processing (MMBtu/d) | 246,000 | 262,000 |
| **NTX** | | |
| Gathering and Transportation (MMBtu/d) | 1,087,000 | 1,181,000 |
| Processing (MMBtu/d) | 394,000 | 319,000 |
| **PNGL** | | |
| Processing (MMBtu/d) | 492,000 | 904,000 |
| NGL Fractionation (Gals/d) | 1,294,000 | 1,179,000 |
| **ORV*** | | |
| Crude Oil Handling (Bbls/d) | 9,700 | — |
| Brine Disposal (Bbls/d) | 7,800 | — |



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* Crude oil handling from PNGL is included in ORV reported volumes.

***Three Months Ended March 31, 2013 Compared to Three Months Ended March 31, 2012***

*Gross Operating Margin.* Gross operating margin was $104.7 million for the three months ended March 31, 2013 compared to $99.8 million for the three months ended March 31, 2012, an increase of $4.9 million, or 4.9%. The overall increase was due to the July 2012 acquisition of the ORV assets, increased throughput on our Permian Basin systems, increase in NGL fractionation and marketing activity and increase from our south Louisiana NGL fractionation and marketing activity. The following provides additional details regarding this change in gross operating margin:

- The ORV segment contributed a total increase of $14.2 million to our gross operating margin for the three months ended March 31, 2013. Gross operating margins from crude oil and condensate handling and brine disposal and handling were $9.7 million and $4.5 million, respectively.

- The NTX segment had a decrease in gross operating margin of $2.4 million for the three months ended March 31, 2013 compared to the three months ended March 31, 2012. Gross operating margin increased by $2.4 million from our gas processing facilities primarily due to increased throughput on our Permian Basin systems. This increase was offset by a decline in our throughput volumes on the gathering and transmission assets resulting in a decrease in gross operating margin of $4.4 million.

- The PNGL segment had a gross operating margin increase of $1.2 million for the three months ended March 31, 2013 compared to the three months ended March 31, 2012. Our NGL fractionation and marketing activities contributed $7.3 million of the gross operating margin increase due to improved margins from seasonal pricing spreads and increased NGL volumes from truck and rail activity. These increases were largely offset by a combined gross operating margin decrease of $6.7 million from our south Louisiana processing plants due to the less favorable processing environment. The PNGL segment also includes our crude oil terminal activity in south Louisiana, which contributed $0.6 million of gross operating margin increase.

- The LIG segment had a decrease in gross operating margin of $8.1 million for the three months ended March 31, 2013 compared to the three months ended March 31, 2012. The majority of the decrease is attributed to a weaker processing environment. Gross operating margins decreased by $3.1 million from our Gibson and Plaquemine plants and decreased by $1.8 million from gas processed for our account by a third-party processor. Gross operating margins decreased by $3.2 million on the gathering and transmission assets due to sales volumes lost related to the Bayou Corne sinkhole and lower blending and treating fees for first quarter of 2013 as compared to same period in 2012. Although our north LIG system in the Haynesville Shale had volume declines, most of these volume declines were associated with gas transported under firm transportation agreements so we only realized a slight decrease in our transportation fee on our north LIG system.

*Operating Expenses.* Operating expenses were $37.3 million for the three months ended March 31, 2013 compared to $27.8 million for the three months ended March 31, 2012, an increase of $9.5 million, or 34.3%. This increase in operating expenses includes a total increase of $7.1 million related to the direct operating costs of the July 2012 acquisition of the ORV assets (as set out in more detail in the bullets below). The primary contributors to the total increase are as follows:

- our labor and benefits expense increased by $4.6 million related to the acquisition of our ORV assets and an increase in employee headcount for activity related to project expansions in our PNGL segment;

- our rents, lease and vehicle expense increased by $1.9 million related to the acquisition of our ORV assets;

- our utilities, fees and services, including operating and construction fees, increased by $1.5 million related to the acquisition of our ORV assets and an increase in expenses for our Permian Basin systems, which had a full quarter of operations during 2013 as compared to a partial quarter of operations during 2012; and

- our ad valorem tax expense increased by $0.8 million due to project expansions.

*General and Administrative Expenses.* General and administrative expenses were $18.2 million for the three months ended March 31, 2013 compared to $15.0 million for the three months ended March 31, 2012, an increase of $3.3 million, or 21.9%. The increase is primarily due to the following:



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- our salaries, wages and benefits increased by $0.1 million due to an increase in headcount;

- our bad debt expense increased by $0.2 million;

- our stock based compensation expense increased by $2.3 million, including $2.0 million attributable to certain bonuses paid in March 2013 in the form of stock and units awards that immediately vested; and

- our utilities and other office supply fees increased by $0.4 million.

*(Gain)/Loss on Derivatives.* We had a loss on derivatives of $0.5 million for the three months ended March 31, 2013 compared to a loss of $2.2 million for the three months ended March 31, 2012. The derivative transaction types contributing to the net loss are as follows (in millions):

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| | 2013 | | 2012 | |
| | Total | Realized | Total | Realized |
| Basis swaps | $ 0.6 | $ 1.3 | $ 2.3 | $ 0.7 |
| Processing margin hedges | (0.5) | (0.3) | 0.2 | 0.9 |
| Liquids Swaps - non-designated | 0.3 | — | 0.1 | — |
| Other | 0.1 | 0.1 | (0.4) | (0.6) |
| Net loss on derivatives | $ 0.5 | $ 1.1 | $ 2.2 | $ 1.0 |

*Depreciation and Amortization*. Depreciation and amortization expenses were $33.7 million for the three months ended March 31, 2013 compared to $32.2 million for the three months ended March 31, 2012, an increase of $1.5 million, or 4.8%. This increase includes $3.4 million additional depreciation due to net asset additions including $2.3 million related to the acquisition of the ORV assets and $0.7 million related to net additions in the Permian area. These additions were partially offset by decreased amortization of $0.4 million related to Sabine Pass Plant intangible amortization which was fully amortized in December 2012 and $1.5 million of decreased intangible amortization related to the revision in future estimated throughput volumes attributable to the dedicated acreage purchased with our gathering system in North Texas.

*Interest Expense*. Interest expense was $20.3 million for the three months ended March 31, 2013 compared to $19.4 million for the three months ended March 31, 2012, an increase of $0.9 million, or 4.6%. Net interest expense consists of the following (in millions):

| | Three Months Ended March 31, | |
|---|---|---|
| | 2013 | 2012 |
| Senior notes | $ 20.5 | $ 16.1 |
| Bank credit facility | 1.3 | 1.6 |
| Capitalized interest | (3.9) | — |
| Amortization of debt issue costs | 2.0 | 1.7 |
| Other | 0.4 | — |
| Total | $ 20.3 | $ 19.4 |

*Equity in losses of limited liability company.* Equity in losses of limited liability company were $0.1 million for the three months ended March 31, 2013 compared to no equity in earnings of limited liability company for the three months ended March 31, 2012 related to our HEP equity investment.

*Income Tax Expense.* Income tax expense was $0.7 million for the three months ended March 31, 2013 compared to $0.4 million for the three months ended March 31, 2012, an increase of $0.3 million. The increase is due to income taxes attributable to the new, wholly owned corporate entity that was formed to acquire the ORV assets.





**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, 2012.

**Liquidity and Capital Resources**

*Cash Flows from Operating Activities.* Net cash provided by operating activities was $9.5 million for the three months ended March 31, 2013 compared to net cash provided by operating activities of $11.4 million for three months ended March 31, 2012. Income before non-cash income and expenses and changes in working capital for comparative periods were as follows (in millions):

| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| Income before non-cash income and expenses | $ 37.4 | $ 40.3 |
| Changes in working capital | $ (27.9) | $ (28.9) |

Cash flow from income before non-cash income and expenses decreased by $2.9 million. Such decrease resulted from an increase in operating and general and administrative expenses due to increased activity related to our Cajun Sibon I and II projects partially offset by an increase in gross operating margin from the three months ended March 31, 2013 compared to the three months ended March 31, 2012.

The change in working capital for 2013 and 2012 primarily relates to normal fluctuations in trade receivable and payable balances due to timing of collections and payments.

*Cash Flows from Investing Activities*. Net cash used in investing activities was $104.0 million for the three months ended March 31, 2013 and $41.0 million for the three months ended March 31, 2012. Our primary investing outflows were capital expenditures, net of accrued amounts, as follows (in millions):

| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| Growth capital expenditures | $ 105.2 | $ 33.4 |
| Maintenance capital expenditures | 5.0 | 2.9 |
| Investment in limited liability company | 13.0 | 4.9 |
| Total | $ 123.2 | $ 41.2 |

Net cash provided by investing activities for the three months ended March 31, 2013 includes proceeds of $18.0 million from our sale of the local distribution companies, which were classified as held for disposition on the balance sheet as of December 31, 2012.

*Cash Flows from Financing Activities.* Net cash provided by financing activities was $94.4 million for the three months ended March 31, 2013 and $26.1 million for the three months ended March 31, 2012. Our primary financing activities consist of the following (in millions):

| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| Net (repayments) borrowings on bank credit facility | $ (59.0) | $ 54.0 |
| Net repayments under capital lease obligations | (0.8 ) | (0.8 ) |
| Debt refinancing costs | (1.5 ) | (1.2 ) |
| Common unit offerings | 185.5 | — |





Distributions to unitholders and our general partner also represent a primary use of cash in financing activities. Total cash distributions made during the three months ended March 31, 2013 and 2012 were as follows (in millions):

| | Three Months Ended March 31, 2013 | Three Months Ended March 31, 2012 |
|---|---|---|
| Common units | $ 26.1 | $ 16.6 |
| Preferred units (1) | — | 4.7 |
| General partner interest (including incentive distribution rights) | 1.6 | 1.2 |
| Total | $ 27.7 | $ 22.5 |

(1) Excludes distributions paid through the issuance of PIK preferred units for the three months ended March 31, 2013.

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 credit facility. We borrow money under our credit facility to fund checks as they are presented. As of March 31, 2013, we had approximately $565.9 million of available borrowing capacity under our credit facility. Changes in drafts payable for the three months ended March 31, 2013 and 2012 were as follows (in millions):

| | Three Months Ended March 31, | |
|---|---|---|
| | 2013 | 2012 |
| Decrease in drafts payable | $ (1.2) | $ (2.7) |

*Working Capital.* We had a working capital deficit of $14.0 million as of March 31, 2013. Changes in working capital may fluctuate significantly between periods even though our trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of our revenues are collected and a large volume of our gas purchases are paid near each month end or the first few days of the following month. As such, receivable and payable balances at any month end may fluctuate significantly depending on the timing of these receipts and payments. During times of significant construction accounts payable balances also include construction related invoices which negatively impact working capital until paid from long-term funds. In addition, although we strive to minimize the amount of time and volumes that our natural gas and NGLs are kept in inventory, these working inventory balances may fluctuate significantly from period to period due to operational reasons and due to changes in natural gas and NGL prices. Working capital also includes our mark to market derivative assets and liabilities associated with our commodity derivatives which may fluctuate significantly due to the changes in natural gas and NGL prices.

*Changes in Operations During 2013.* We have a gas gathering contract with a major producer in our North Texas assets with a primary term that expired August 31, 2012 that was modified to be on a month-to-month basis beginning September 1, 2012. Subsequently, the modified contract was extended for six months at a reduced gathering fee rate which reduced our gross operating margin by approximately $1.2 million per quarter. The contract is currently rolling month to month in evergreen status (under the terms of the previously mentioned six month extension), and we are in the process of finalizing negotiations of a longer term agreement.

We own and operate a high-pressure pipeline and underground natural gas and NGL storage reservoirs and associated facilities near Bayou Corne, Louisiana. In August 2012, a large sinkhole formed in the vicinity of these pipelines and underground storage reservoirs. This sinkhole is situated west of our underground natural gas and NGL storage facility. The cause of the sinkhole is currently under investigation by Louisiana state and local officials. We took a section of our 36-inch-diameter natural gas pipeline located near the sinkhole out of service. Service to certain markets, primarily in the Mississippi River area, has been curtailed or interrupted, and we have worked with our customers to secure alternative natural gas supplies so that disruptions are minimized. We expect that the ongoing overall business impact on the services previously provided by the pipeline, which include gathering, processing, transportation and end-user sales, will be approximately $0.25 to $0.3 million per month while the pipeline section is out of service. We are currently in the initial phase of constructing the replacement pipeline in our rerouted location and anticipate services will resume in third quarter 2013.

We are assessing the potential for recovering our losses from responsible parties, and we are seeking recovery from our insurers. Our insurers, however, have denied our insurance claim for coverage and filed a declaratory judgment asking a court to determine that our insurance policy does not cover this damage. We have sued our insurers for breach of contract due to their refusal to pay our insurance claim for this damage. We have also sued Texas Brine, LLC, the operator of a failed cavern in the area, and its insurers





seeking recovery for this damage. We cannot give assurance that we will be able to fully recover our losses through insurance recovery or claims against responsible parties.

*Capital Requirements.* During the three months ended March 31, 2013, capital investments were $126.5 million, which were funded by internally generated cash flow, borrowings under our credit facility and equity offerings. Our remaining current growth capital spending projection for 2013 is approximately $375.0 million to $425.0 million related to identified growth projects. We expect to fund the growth capital expenditures from the proceeds of borrowing under our bank credit facility and from other debt and equity sources.

*Off-Balance Sheet Arrangements*. No off-balance sheet arrangements existed as of March 31, 2013.

*Total Contractual Cash Obligations.* A summary of contractual cash obligations as of March 31, 2013 is as follows (in millions):

| | Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2013 | 2014 | 2015 | 2016 | 2017 | Thereafter |
| Long-term debt obligations | $ 975.0 | $ — | $ — | $ — | $ — | $ — | $ 975.0 |
| Bank credit facility | 12.0 | — | — | — | 12.0 | — | — |
| Interest payable on fixed long-term debt obligations | 490.1 | 49.9 | 82.2 | 82.2 | 82.2 | 82.2 | 111.4 |
| Capital lease obligations | 29.3 | 3.4 | 4.6 | 4.6 | 4.6 | 6.9 | 5.2 |
| Operating lease obligations | 46.4 | 5.1 | 9.2 | 9.4 | 7.4 | 4.5 | 10.8 |
| Purchase obligations | 6.8 | 6.8 | — | — | — | — | — |
| Consulting agreement | 4.3 | 0.8 | 3.5 | — | — | — | — |
| Inactive easement commitment* | 10.0 | — | — | — | — | — | 10.0 |
| Uncertain tax position obligations | 4.3 | 4.3 | — | — | — | — | — |
| Total contractual obligations | $ 1,578.2 | $ 70.3 | $ 99.5 | $ 96.2 | $ 106.2 | $ 93.6 | $ 1,112.4 |

* Amounts related to inactive easements paid as utilized by the Partnership with balance due at end of 10 years if not utilized.

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis.

The interest payable under the Partnership's credit facility is not reflected in the above table because such amounts depend on the outstanding balances and interest rates, which vary from time to time. However, given the same borrowing amount and rates in effect at March 31, 2013, the cash obligation for interest expense on the Partnership's credit facility would be approximately $0.4 million per year or approximately $0.3 million for the remainder of 2013.

**Indebtedness**

As of March 31, 2013 and December 31, 2012, long-term debt consisted of the following (in millions):

| | March 31, 2013 | December 31, 2012 |
|---|---|---|
| Bank credit facility (due 2016), interest based on Prime and/or LIBOR plus an applicable margin, interest rate at March 31, 2013 and December 31, 2012 was 3.3% and 4.3%, respectively | $ 12.0 | $ 71.0 |

| | | |
|---|---|---|
| Senior unsecured notes (due 2018), net of discount of $9.2 million and $9.7 million, respectively, which bear interest at the rate of 8.875% | 715.8 | 715.3 |
| Senior unsecured notes (due 2022), which bear interest at the rate of 7.125% | 250.0 | 250.0 |
| Debt classified as long-term | $ 977.8 | $ 1,036.3 |

*Credit Facility* As of March 31, 2013, there was $57.1 million in outstanding letters of credit and $12.0 million borrowed under the Partnership's bank credit facility, leaving approximately $565.9 million available for future borrowing based on the borrowing capacity of $635.0 million. However, the financial covenants in the amended credit facility limit the amount of funds that we can borrow. As of March 31, 2013, based on our maximum permitted consolidated leverage ratio (as defined in the amended credit facility), we could borrow approximately $377.3 million of additional funds.The credit facility matures in May 2016. In January





2013, the Partnership amended the credit facility. See Note 3 to the condensed consolidated financial statements titled "Long-Term Debt" for further details.

**Recent Accounting Pronouncements**

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 2013-02-Comprehensive Income (ASC 220), "*Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*." This update requires that we report reclassifications out of accumulated other comprehensive income and their effect on net income by component or financial statement line. We have included the required disclosures in the notes of our financial statements for the three months ended March 31, 2013.

We have reviewed all other recently issued accounting pronouncements that became effective during the three months ended March 31, 2013 and have determined that none would have a material impact to our Unaudited Condensed Consolidated Financial Statements.

**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, 2012, 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, NGLs and crude oil. In addition, we are exposed to the risk of changes in interest rates on our floating rate debt.

Comprehensive financial reform legislation was signed into law by the President on July 21, 2010. The legislation calls for the CFTC to regulate certain markets for derivative products, including over-the-counter ("OTC") derivatives. The CFTC has issued several new relevant regulations and other rulemakings are pending at the CFTC, the product of which would be rules that implement the mandates in the new legislation to cause significant portions of derivatives markets to clear through clearinghouses. The legislation and new regulations may also require counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and to generate sufficient cash flow to pay quarterly distributions at current levels or at all. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition and our results of operations.

**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 ("POL") 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.

Gas processing margins by contract types and gathering, transportation and crude handling margins as a percent of total gross operating margin for the comparative year-to-date periods are as follows:

| | Three Months Ended March 31, 2013 | 2012 |
|---|---|---|
| Gathering, transportation and crude handling margin | 64.1 % | 58.2 % |
| Gas processing margins: | | |
| Processing margin | 4.2 % | 18.0 % |
| Percent of liquids | 9.6 % | 7.4 % |
| Fee based | 22.1 % | 16.4 % |
| Total gas processing | 35.9 % | 41.8 % |
| Total | 100.0 % | 100.0 % |

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.

We have hedged our exposure to declines in prices for NGL volumes produced for our account. We hedge our exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options.

We have hedges in place at March 31, 2013 covering a portion of the liquids volumes we expect to receive under POL contracts. The hedges were done via swaps and are 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).

| Period | Underlying | Notional Volume | We Pay | We Receive * | Fair Value Asset/(Liability) (In thousands) |
|---|---|---|---|---|---|
| April 2013 — December 2013 | Ethane | 79 (MBbls) | Index | $ 0.4205 /gal | $ 391 |
| April 2013 — December 2013 | Propane | 43 (MBbls) | Index | $ 1.1813 /gal | 381 |
| April 2013 — December 2013 | Iso Butane | 20 (MBbls) | Index | $ 1.6938 /gal | 152 |
| April 2013 — December 2013 | Normal Butane | 28 (MBbls) | Index | $ 1.6734 /gal | 285 |
| April 2013 — December 2013 | Natural Gasoline | 33 (MBbls) | Index | $ 2.1649 /gal | 104 |
| | | | | | $ 1,313 |

*weighted average



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| Period | Underlying | Notional Volume | We Pay | We Receive * | Fair Value Asset/(Liability) (In thousands) |
|---|---|---|---|---|---|
| January 2014 — December 2014 | Propane | 47 (MBbls) | Index | $ 0.9555 /gal | $ (17) |
| | | | | | $ (17) |

*weighted average

In relation to our POL contracts, as set forth above, we have hedged 44.5% of our total volumes at risk through December 2013 and hedged 7.4% of our total volumes at risk for 2014.

We have hedges in place at March 31, 2013 covering the fractionation spread risk related to our processing margin contracts as set forth in the following tables:

| Period | Underlying | Notional Volume | We Pay | We Receive | Fair Value Asset/(Liability) (In thousands) |
|---|---|---|---|---|---|
| April 2013—December 2013 | Propane | 41 (MBbls) | Index | $ 1.2548 /gal* | $ 499 |
| April 2013—December 2013 | Normal Butane | 42 (MBbls) | Index | $ 1.6714 /gal* | 415 |
| April 2013—December 2013 | Natural Gasoline | 24 (MBbls) | Index | $ 2.2386 /gal* | 145 |
| April 2013—December 2013 | Natural Gas | 1,900 (MMBtu/d) | $3.6005 /MMBtu* | Index | 272 |
| | | | | | $ 1,331 |

*weighted average

In relation to our fractionation spread risk, as set forth above, we have hedged 14.4% of our total liquids volumes at risk and 17.0% of the related total PTR volumes through December 2013.

We are 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 3.3% 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.

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 March 31, 2013, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $2.4 million. The aggregate effect of a hypothetical 10% increase in gas and NGL prices would result in a decrease of approximately $1.6 million in the net fair value asset of these contracts as of March 31, 2013 to a net fair value asset of approximately $0.8 million.

**Interest Rate Risk**

We are exposed to interest rate risk on our variable rate bank credit facility. At March 31, 2013, we had $12.0 million in borrowings under this facility. A 1% increase or decrease in interest rates would change our annual interest expense by approximately $0.1 million for the year.

At March 31, 2013, we had fixed rate debt obligations of $715.8 and $250.0 million, consisting of our senior unsecured notes with an interest rate of 8.875% and 7.125%, respectively. The fair value of the fixed rate obligations for the 2018 Notes and 2022 Notes





was approximately $784.8 million and $268.1 million, respectively, as of March 31, 2013. We estimate that a 1% decrease or increase in interest rates would increase or decrease the fair value of the 2018 Notes and the 2022 Notes by $29.5 million and $17.3 million, respectively.

**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 (March 31, 2013), 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 within the time period specified in the applicable rules and forms, and that such information is accumulated and communicated to management, including the 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 March 31, 2013 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 9, "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 March 31, 2013 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, 2012 except as listed below.

*A default under Crosstex Energy, Inc.'s Subsidiary's credit facility could have an adverse effect on the price of our common units and could result in a change of control of our general partner.*

A subsidiary of Crosstex Energy, Inc., the owner of our general partner ("CEI"), has entered into a credit facility that is initially secured by a first priority lien on 10,700,000 of our common units and that is guaranteed by CEI. A decline in the price of our common units could require CEI to pledge additional common units or to sell common units that it owns (directly or indirectly) in an expedited manner. Although we are not a party to this credit facility, if a default under such credit facility were to occur, the lenders could foreclose on the pledged units and/or CEI may be forced to sell its assets, including its interest in our general partner or the remaining common units owned by it, to fund any repayment obligations. Any such sale of our common units that it owns (directly or indirectly) could have an adverse effect on the market price of our common units. In addition, any sale by CEI of our general partner would allow the new owner of our general partner to replace the board of directors and officers of our general partner with its own choices and to control the decisions taken by the board of directors and officers. Moreover, any change of control of our general partner (i) would permit the lenders under our credit facility to declare all amounts thereunder immediately due and payable and (ii) may permit the holders of the two outstanding series of our senior unsecured notes to require us to repurchase such notes. If any such event occurs, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders.

*The credit and risk profile of CEI could adversely affect our risk profile, which could increase our borrowing costs, hinder our ability to raise capital or impact future credit ratings.*





The credit and business risk profiles of CEI may factor into the credit evaluations of us. This is because our general partner can exercise significant influence over our business activities, including cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered in credit evaluations of us is the financial condition of CEI or its subsidiaries, including the degree of their financial leverage and their dependence on cash flow from us to service their indebtedness.

Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us, our general partner, CEI and its subsidiaries, our credit ratings and business risk profile could be adversely affected if the credit ratings and risk profiles of our general partner, CEI or its subsidiaries were viewed as substantially lower or more risky than ours.

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**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 |
|---|---|---|
| 2.1*** | — | Stock Purchase and Sale Agreement, dated as of May 7, 2012, by and among Energy Equity Partners, L.P., the Individual Owners (as defined therein), Clearfield Energy, Inc., Clearfield Holdings, Inc., West Virginia Oil Gathering Corporation, Appalachian Oil Purchasers, Inc., Kentucky Oil Gathering Corporation, Ohio Oil Gathering Corporation II, Ohio Oil Gathering Corporation III, OOGC Disposal Company I, M&B Gas Services, Inc., Clearfield Ohio Holdings, Inc., Pike Natural Gas Company, Eastern Natural Gas Company, Southeastern Natural Gas Company and Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated May 7, 2012, filed with the Commission on May 8, 2012). |
| 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 | — | Certificate of Amendment to the Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.2 to our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2012). |
| 3.3 | — | 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). |
| 3.4 | — | 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). |
| 3.5 | — | 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). |
| 3.6 | — | 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). |
| 3.7 | — | Amendment No. 4 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of September 13, 2012 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated September 13, 2012, filed with the Commission on September 14, 2012). |
| 3.8 | — | 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). |
| 3.9 | — | 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). |
| 3.10 | — | 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). |
| 10.1 | | Seventh Amendment to Amended and Restated Credit Agreement, dated as of January 28, 2013, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 28, 2013, filed with the Commission on January 29, 2013). |
| 10.2 | | Common Unit Purchase Agreement, dated as of January 9, 2013, by and among Crosstex Energy, L.P., and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 8, 2013, filed with the Commission on January 10, 2013). |



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| Number | | Description |
|---|---|---|
| 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 the Principal Financial Officer of the Company pursuant to 18 U.S.C. Section 1350. |
| 101** | — | The following financial information from Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations for the three months ended March 31, 2013 and 2012, (ii) Condensed Consolidated Balance Sheets as of March 31, 2013 and December 31, 2012, (iii) Consolidated Statements of Cash Flows for the three months ended March 31, 2013 and 2012, (iv) Consolidated Statements of Comprehensive Income for the three months ended March 31, 2013 and 2012, (v) Consolidated Statements of Changes in Partners' Equity for the three months ended March 31, 2013, and (vi) the Notes to Condensed Consolidated Financial Statements. |

* Filed herewith.
** Furnished herewith.
*** Pursuant to Item 601(b)(2) of Regulation S-K, the Registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.



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**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, LLC,
its general partner

By: /s/ MICHAEL J. GARBERDING
Michael J. Garberding
Executive Vice President and Chief Financial Officer

May 9, 2013

**Exhibit 31.1**

**CERTIFICATIONS**

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy GP, LLC, 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: May 9, 2013

**Exhibit 31.2**

**CERTIFICATIONS**

I, Michael J. Garberding, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, 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/ MICHAEL J. GARBERDING

MICHAEL J. GARBERDING
*Executive Vice President and Chief Financial Officer*
*(principal financial and accounting officer)*

Date: May 9, 2013

**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 March 31, 2013 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 Michael J. Garberding, 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*

May 9, 2013

/s/ MICHAEL J. GARBERDING
Michael J. Garberding
*Chief Financial Officer*

May 9, 2013

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.