**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**

# Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended December 31, 2008**

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

**(Registrant's telephone number, including area code)**

**(214) 953-9500**

**SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:**

| **Title of Each Class** | **Name of Exchange on which Registered** |
|---|---|
| Common Units Representing Limited Partnership Interests | The NASDAQ Global Select Market |

**SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:**
**None.**

Indicate by check mark if registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 Securities 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 ☑

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $437,179,020 on June 30, 2008, based on $28.68 per unit, the closing price of the Common Units as reported on the NASDAQ Global Select Market on such date.

At February 16, 2009, there were 44,942,955 common units and 3,875,340 senior subordinated series D units outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE:**
None.

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**DESCRIPTION**

**CROSSTEX ENERGY, L.P.**

**PART I**

**Item 1.** ***Business***

**General**

Crosstex Energy, L.P. is a publicly traded Delaware limited partnership. Our Common Units are listed on the NASDAQ Global Select Market under the symbol "XTEX". Our business activities are conducted through our subsidiary, Crosstex Energy Services, L.P., a Delaware limited partnership (the "Operating Partnership") and the subsidiaries of the Operating Partnership. Our executive offices are located at 2501 Cedar Springs, Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.crosstexenergy.com. In the "Investors" section of our web site, we post the following filings as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: our annual report on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our web site are available free of charge. In this report, the terms "Partnership" and "Registrant," as well as the terms "our," "we," "us" and "its," are sometimes used as abbreviated references to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. together with its consolidated subsidiaries, including the Operating Partnership.

We are an independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids, or NGLs. We connect the wells of natural gas producers in our market areas to our gathering systems, treat natural gas to remove impurities to ensure that it meets pipeline quality specifications, 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 points 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 have two operating segments, Midstream and Treating. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, while our Treating division focuses on the removal of impurities from natural gas to meet pipeline quality specifications. Our primary Midstream assets include over 5,700 miles of natural gas gathering and transmission pipelines, 12 natural gas processing plants and four fractionators. Our gathering systems consist of a network of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. Our processing plants remove NGLs from a natural gas stream and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso- and normal butanes and natural gasoline. Our primary Treating assets include approximately 225 natural gas amine-treating plants and 56 dew point control plants. Our natural gas treating plants remove carbon dioxide and hydrogen sulfide from natural gas prior to delivering the gas into pipelines to ensure that it meets pipeline quality specifications. See Note 17 to the consolidated financial statements for financial information about these operating segments.

Set forth in the table below is a list of our acquisitions since January 1, 2004.

| Acquisition | Acquisition Date | Purchase Price (In thousands) | Asset Type |
|---|---|---|---|
| LIG Acquisition | April 2004 | 73,692 | Gathering and transmission systems and processing plants |
| Crosstex Pipeline Partners | December 2004 | 5,100 | Gathering pipeline |
| Graco Operations | January 2005 | 9,257 | Treating plants |
| Cardinal Gas Services | May 2005 | 6,710 | Treating plants and gas processing plants |
| El Paso Acquisition | November 2005 | 480,976 | Processing and liquids business (including 23.85% interest in Blue Water gas processing plant) |
| Hanover Amine Treating | February 2006 | 51,700 | Treating plants |
| Blue Water Acquisition | May 2006 | 16,454 | Additional 35.42% interest in gas processing plant |
| Chief Acquisition | June 2006 | 475,287 | Gathering and transmission systems and carbon dioxide treating plant |
| Cardinal Gas Solutions | October 2006 | 6,330 | Dew point control plants and treating plants |

Our general partner interest is held by Crosstex Energy GP, L.P., a Delaware limited partnership. Crosstex Energy GP, LLC, a Delaware limited liability company, is Crosstex Energy GP, L.P.'s general partner. Crosstex Energy GP, LLC manages our operations and activities and employs our officers. Crosstex Energy GP, L.P. and Crosstex Energy GP, LLC are indirect, wholly-owned subsidiaries of Crosstex Energy, Inc., or CEI.

As generally used in the energy industry and in this document, the following terms have the following meanings:

/d = per day
Bbls = barrels
Bcf = billion cubic feet
Btu = British thermal units
Mcf = thousand cubic feet
MMBtu = million British thermal units
MMcf = million cubic feet
NGL = natural gas liquid

Capacity volumes for our facilities are measured based on physical volume and stated in cubic feet (Bcf, Mcf or MMcf). Throughput volumes are measured based on energy content and stated in British thermal units (Btu or MMBtu). A volume capacity of 100 MMcf generally correlates to volume throughput of 100,000 MMBtu.

**Recent Developments**

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. Numerous events during 2008 have severely restricted current liquidity in the capital markets throughout the United States and around the world. The ability to raise money in the debt and equity markets has diminished significantly and, if available, the cost of funds has increased substantially. One of the features driving investments in master limited partnerships ("MLPs") , including the Partnership, over the past few years has been the distribution growth offered by MLPs due to liquidity in the financial markets for capital investments to grow distributable cash flow through development projects and acquisitions. Future growth opportunities have been and are expected to continue to be constrained by the lack of liquidity in the financial markets.

In addition, our business has been significantly impacted by the substantial decline in crude oil prices during the last half of 2008 from a high of approximately $145 per Bbl in July 2008 to a low of approximately $34 per Bbl in December 2008 (based on NYMEX futures daily close prices for the prompt month), a 76.7% decline, and the

related 78.2% decline in NGL prices from a high of $2.19 per gallon in July 2008 to a low of $0.48 per gallon in December 2008 (based on the OPIS Mt. Belvieu daily average spot liquids prices). Crude oil prices reflected on NYMEX during January and February 2009 have fluctuated, to a lesser extent, between $49 per Bbl and $35 per Bbl while the OPIS Mt. Belvieu NGL prices have improved slightly ranging from $0.81 per gallon and $0.62 per gallon. The declines in NGL prices have negatively impacted our gross margin for the fourth quarter of 2008 and could continue to negatively impact our gross margin (revenue less cost of gas purchases) in 2009. A significant percentage of inlet gas at our processing plants is settled under percent of liquids ("POL") agreements or fractionation margin (margin) contracts. Over the past two years the inlet processing volumes associated with POL and margin contracts were approximately 70%, on a combined basis, of the total volume of gas processed. The POL fees are denominated in the form of a share of the liquids extracted. Therefore, fee revenue under a POL agreement is directly impacted by NGL prices and the decline of these prices in 2008 contributed to a significant decline in gross margin from processing. Under the POL settlement terms, we are not responsible for the fuel or shrink associated with processing. Under margin contracts we realize a gross margin from processing based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state and the cost of fuel to extract. This is often referred to as the "fractionation spread". During the last half of 2008 the fractionation spread narrowed significantly as the value of NGLs decreased more than the value of the gas and fuel associated with the processed gas. Thus the gross margin realized under these margin contracts was also negatively impacted due to the commodity price environment. If the current weakness in the economy continues for a prolonged period, it would likely further reduce demand for gas and for NGL products, such as ethane, a primary feedstock for the petrochemical and manufacturing industries, and result in continued lower natural gas and NGL prices. Although we have seen some improvement in NGL prices and the fractionation spread in the early months of 2009 over the levels experienced in December 2008, we believe that our processing margins in 2009 will be substantially lower than the processing margins realized in 2008 based on current market indicators. For the year ended December 31, 2008, approximately 38.7% of our gross margin was attributable to gas processing as compared to 46.1% of our gross margin for the year ended December 31, 2007. See Item 7A, "Quantitative and Qualitative Disclosures about Market Risk-Commodity Price Risk" for a description of our contractual processing arrangements.

Natural gas prices have declined by approximately 61.0%, from a high of $13.58 per MMBtu in July 2008 to a low of $5.29 per MMBtu in December 2008 (based on NYMEX futures daily close prices for the prompt month). Natural gas prices have declined even further during January and February 2009 with prices ranging from $6.07 in early January to $4.01 in mid-February. Many of our customers finance their drilling activity with cash flow from operations, which have been negatively impacted by the declines in natural gas and crude oil prices, or through the incurrence of debt or issuance of equity, which markets have been adversely impacted by global financial market conditions. We believe that the adverse price changes coupled with the overall downturn in the economy and the constrained capital markets will put downward pressure on drilling budgets for gas producers which could result in lower volumes being transported on our pipeline and gathering systems and processed through our processing plants. We have seen a decline in drilling activity by gas producers in our areas of operation during the fourth quarter of 2008. In addition, industry drilling rig count surveys published in early 2009 show substantial declines in rigs in operation as compared to 2008. Several of our customers, including one of our largest customers in the Barnett Shale, have recently announced drilling plans for 2009 that are substantially below their drilling levels during 2008.

Our business was also negatively impacted by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September 2008. Although the majority of our assets in Texas and Louisiana sustained minimal physical damage from these hurricanes and promptly resumed operations, several offshore production platforms and pipelines that transport gas production to our Pelican, Eunice, Sabine Pass and Blue Water processing plants in south Louisiana were damaged by the storms. Some of the repairs to these offshore facilities were completed during the fourth quarter of 2008 but we do not anticipate that gas production to our south Louisiana plants will recover to pre-hurricane levels until mid-2009, when all repairs are expected to be complete. Additionally, one of our south Louisiana processing plants, the Sabine Pass processing plant, which is located on the shoreline of the Louisiana Gulf Coast, sustained some physical damage. The Sabine Pass processing plant was repaired during the fourth quarter of 2008 and the plant was returned to service in early January 2009. Our operations in north Texas were also impacted by these hurricanes because operations at Mt. Belvieu, Texas, a central distribution point for NGL sales where several fractionators are located which fractionate NGLs from the entire United States, were interrupted as a

result of these storms. These storms resulted in an adverse impact to our gross margin of approximately $22.9 million.

Two of our facilities, one in south Louisiana and one in north Texas, were also partially damaged by fires during 2008. Although substantially all of the property repairs were covered by insurance, our Sabine Pass processing plant in south Louisiana was out of service for approximately one month. The loss of operating income due to the fire at the Godley compressor station in north Texas was minimal because we were successful in rerouting the gas to our other facilities in the area until the damaged compressor was replaced. The estimated loss in gross margin as a result of these fires was $0.9 million.

**Business Strategy**

Until the occurrence of the recent developments described above, our long-term strategy has been to increase distributable cash flow per unit by accomplishing economies of scale through new construction or expansion in core operating areas and making accretive acquisitions of assets that are essential to the production, transportation and marketing of natural gas and NGLs. In response to these recent events, we adjusted our business strategy in the fourth quarter 2008 and for 2009 to focus on maximizing our liquidity, maintaining a stable asset base, improving the profitability of our assets by increasing their utilization while controlling costs and reducing our capital expenditures by undertaking the following steps:

- We intend to operate our existing asset base to enhance profitability by undertaking initiatives to maximize utilization by improving operations, reducing operating costs and renegotiating contracts, when appropriate, to improve our economics. We have a solid base of assets, including midstream and treating assets that are well located to benefit from the continued growth in the Barnett Shale in north Texas and the new growth anticipated from the Haynesville Shale located in northern Louisiana and eastern Texas.
- We amended our bank credit facility and our senior secured note agreements in November 2008 and again in February 2009 to negotiate terms that facilitate our compliance with debt covenants while we operate our assets during the current difficult economic conditions. The terms of the amended agreements allow us to maintain a higher level of leverage and to maintain a lower interest coverage ratio; however, our interest costs will increase and our ability to pay distributions and incur additional indebtedness will be restricted when we are operating at higher leverage ratios. The terms of these agreements are described more fully under “Amendments to Credit Documents” below and in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”
- We have lowered our distribution level from $0.63 per unit for the second quarter of 2008 to $0.25 per unit for the fourth quarter of 2008. The amended terms of our credit facility and senior secured note agreement prohibit us from making distributions unless our leverage ratio is below certain levels and the PIK notes have been repaid as discussed more fully under “Amendments to Credit Documents.” We do not expect that we will meet these conditions in 2009.
- We sold certain non-strategic assets in November 2008 and used the proceeds from such sales to reduce our outstanding borrowings under our bank credit facility. We received $85.0 million for the sale of our 12.4% interest in the Seminole gas processing plant to an unaffiliated third party and we received $20.0 million for the assignment of a transportation contract right to another unaffiliated third party. We may consider selling other non-strategic assets during 2009 and use the proceeds to further reduce our indebtedness if we are able to obtain attractive offers for such assets.
- We have reduced our budgeted capital expenditures significantly for 2009. Total growth capital investments in the calendar year 2009 are currently anticipated to be approximately $100.0 million and primarily relate to capital projects in north Texas and Louisiana pursuant to contract obligations with producers. Our ability to grow our asset base through the continued development of our north Texas and Louisiana assets or through acquisitions will be limited due to our lack of access to capital markets and due to restrictions under our debt agreements. We will use cash flow from operations and existing capacity under our bank credit facility to fund our reduced capital spending plan during 2009. Capital expenditures in future periods will be limited to cash flow from operating activities and to existing capacity under our bank credit facility.

- We have reduced our general and administrative expenses by reducing our work force by approximately 8.0% through the elimination of open positions and certain corporate positions and minimizing all non-essential costs. We have also reduced our operating expenses by reducing overtime and renegotiating certain contracts to reduce monthly costs and by eliminating certain equipment rentals.

**Amendments to Credit Documents**

On November 7, 2008, we amended our bank credit facility and senior secured note agreement to, among other things, revise the leverage ratio and interest coverage ratio requirements to ease the covenant restrictions under the agreements and to permit us to sell certain assets, including the non-strategic asset dispositions described in "Business Strategy" above. The amendments also included provisions that increased the interest rates under both our bank credit facility and our senior note agreement by 1.25% per annum and increased the other fees associated with our bank credit facility.

Due to the continued decline in commodity prices and the deterioration in processing margins, we determined that there was a significant risk that the amended terms negotiated in November would not be sufficient to allow us to operate during 2009 without triggering a covenant default under our bank facility and the senior secured note agreement. On February 27, 2009, we amended our bank credit facility and the senior secured note agreement to include revised terms that facilitate our compliance with debt covenants while we operate our assets during the current difficult economic conditions. In general terms, the amended agreement allows us to maintain a higher level of leverage and to maintain a lower interest coverage ratio; however, our interest costs will increase, our ability to incur additional indebtedness will be restricted when we are operating at higher leverage ratios and our ability to pay distributions will be prohibited until our leverage ratio is significantly lower and we repay the PIK notes (as defined below).

Under the amended bank credit facility, if we are operating at higher leverage ratios, our interest margin over the London Interbank Offering Rate ("LIBOR") on our LIBOR borrowings will generally increase to 4.00% per annum, which represents an increase of 2.25% over the comparative interest rate under the credit agreement prior to the November and February amendments. The fees charged for letters of credit will also increase by 2.25%. The interest margin on our LIBOR borrowings will decline from the maximum level of 4.00% to a low of 2.75% when our leverage ratios are at the lower end of the range. The amendment also sets a floor for the LIBOR interest rate of 2.75% per annum, which means, effective as of February 27, 2009, borrowings under the bank credit facility accrue interest at the rate of 6.75% based on the LIBOR rate in effect on such date and our current leverage ratio. The interest rates and leverage ratios under the amended agreement are described more fully in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations—Description of Indebtedness."

Commencing February 27, 2009 the interest rate we pay on all of the senior secured notes will increase by 2.25% per annum over the comparative interest rates under the senior note agreement prior to the November and February amendments. As a result of this rate increase, the weighted average cash interest rate on the outstanding balance on the senior secured notes is approximately 9.25% as of February 2009.

Under the amended senior note agreement, the senior secured notes will accrue additional interest of 1.25% in the form of an increase in the principal amount of the senior secured notes (the "PIK notes") unless our leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter. All PIK interest will be payable 180 days after the maturity of the bank credit facility.

Per the terms of the amended senior secured note agreement, commencing on the date we refinance our bank credit facility, the interest rate payable in cash on our senior secured notes will increase by 1.25% per annum for any quarter if our leverage ratio as of the most recently ended fiscal quarter was greater than or equal to 4.25 to 1.00. In addition, commencing on June 30, 2012, the interest rate payable in cash on our senior secured notes will increase by 0.50% per annum for any quarter if our leverage as of the most recently ended fiscal quarter was greater than or equal to 4.00 to 1.00, but this incremental interest will not accrue if we are paying the incremental 1.25% per annum of interest described in the preceding sentence.

Under our amended bank credit facility and senior secured note agreement, we must pay a leverage fee if we do not prepay debt and permanently reduce the banks' commitments by the cumulative amounts of $100.0 million on

September 30, 2009, $200.0 million on December 31, 2009 and $300.0 million on March 31, 2010. If we fail to meet any de-leveraging target, we must pay a leverage fee on such date, equal to the product of the aggregate commitment outstanding under our bank credit facility and the outstanding amounts of senior secured note agreement on such date, and 1.0% on September 30, 2009, 1.0% on December 31, 2009, and 2.0% on March 31, 2010. This leverage fee will accrue on the applicable date, but not be payable until we refinance our bank credit facility.

Under our amended bank credit facility and senior secured note agreement, we may not make quarterly distributions to our unitholders unless the PIK notes have been repaid and the leverage ratio, as defined in the agreements, is less than 4.25 to 1.00. If the leverage ratio is between 4.00 to 1.00 and 4.25 to 1.00, we may make the minimum quarterly distributions of up to $0.25 per unit if the PIK notes have been repaid. If the leverage ratio is less than 4.00 to 1.00, we may make quarterly distributions to unitholders from available cash as provided by our partnership agreement if the PIK notes have been repaid. The PIK notes are due six months after the earlier of the refinancing or maturity of our bank credit facility. Based on our forecasted leverage ratios for 2009, we do not anticipate making quarterly distributions in 2009 other than the distribution paid in February 2009 related to fourth quarter 2008 operating results. We will not be able to make distributions to our unitholders in future periods if our leverage ratio does not improve and the PIK notes are not first repaid.

Our amended credit facility and senior secured note agreement also limit our annual capital expenditures (excluding maintenance capital expenditures) to $120.0 million in 2009 and $75.0 million in 2010 and in each year thereafter (with unused amounts in any year being carried forward to the next year). It is unlikely that we will be able to make any acquisitions based on the terms of our credit facility and the current condition of the capital markets because, as discussed below, we may only use a portion of the proceeds from the incurrence of unsecured debt and the issuance of equity to make such acquisitions.

Our amended credit facility and senior secured note agreement also require us to repay outstanding indebtedness from proceeds from asset sales and debt and equity issuances. All proceeds from asset sales must be used to prepay indebtedness. All proceeds from the incurrence of unsecured debt and 50% of the proceeds from equity issuances must be used to prepay indebtedness if our leverage ratio exceeds 4.50 to 1.00. If our leverage ratio is less than 4.50 to 1.00 but greater than 3.50 to 1.00, 50% of the debt proceeds and 25% of the equity proceeds must be used to prepay indebtedness. If our leverage ratio is less than 3.50 to 1.00, there are no prepayment requirements from debt and equity issuances. The prepayments are to be applied pro rata based on total debt (including letter of credit obligations) outstanding under the bank credit agreement and the total debt outstanding under the note agreements described below. Any prepayments of advances on the bank credit facility from proceeds from asset sales, debt or equity issuances will permanently reduce the borrowing capacity or commitment under the facility in an amount equal to 100% of the amount of the prepayment. Any such commitment reduction will not reduce the banks' $300.0 million commitment to issue letters of credit under our bank facility.

We were in compliance with all debt covenants at December 31, 2008 and 2007 and expect to be in compliance with debt covenants for the next twelve months.

For more information on the amendments to our bank credit facility and senior secured note agreement, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations-Description of Indebtedness."

**Acquisitions and Expansion in Recent Years**

*North Texas Assets.* Our North Texas Pipeline, or NTP, which commenced service in April 2006, consists of a 133-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas. The initial capacity of the NTP was approximately 250 MMcf/d. In 2007, we expanded the capacity on the NTP to a total of approximately 375 MMcf/d. The NTP connects production from the Barnett Shale to markets in north Texas and to markets accessed by the Natural Gas Pipeline Company, or NGPL, Kinder Morgan, Houston Pipeline, or HPL, Atmos and other markets. As of December 2008, the total throughput on the NTP was approximately 300,000 MMBtu/d. The NTP also will interconnect with a new interstate gas pipeline under construction by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing Pipeline, which is expected to be in service in March 2009. The Gulf Crossing Pipeline is expected to provide our customers access to premium midwest and east coast markets.

On June 29, 2006, we expanded our operations in the north Texas area through our acquisition of the natural gas gathering pipeline systems and related facilities of Chief Holdings, LLC, or Chief, in the Barnett Shale for $475.3 million. The acquired systems, which we refer to in conjunction with the NTP and our other facilities in the area as our North Texas Assets, included gathering pipeline, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that acquisition, approximately 160,000 net acres previously owned by Chief and acquired by Devon Energy Corporation, or Devon, simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. The continued expansion of our north Texas gathering systems to handle the growing production in the Barnett Shale was one of our core areas for internal growth during 2007 and 2008 and will continue to be a core area during 2009. Since the date of the acquisition through December 31, 2008, we have connected 444 new wells to our gathering system and significantly increased the dedicated acreage owned by other producers. Our processing capacity in the Barnett Shale is 280 MMcf/d including the Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, our Azle plant, which is a 50 MMcf/d cryogenic processing plant and our Goforth plant, which is a 30 MMcf/d processing plant. In 2007 and 2008, we constructed a 29-mile expansion in north Johnson County to our north Texas gathering systems. The first phase of the expansion commenced operation in September 2007. The last two phases of the expansion commenced operation in May and July of 2008. The total gathering capacity of this 29-mile expansion is currently 235 MMcf/d and is expected to be increased to approximately 400 MMcf/d in April 2009 by the addition of compression. We have also installed two 40 gallon per minute and one 100 gallon per minute amine treating plants to provide carbon dioxide removal capability. As of December 2008, the capacity of our north Texas gathering system was approximately 1,100 MMcf/d and total throughput on our north Texas gathering systems, including the north Johnson County expansion, had increased from approximately 115,000 MMBtu/d at the time of the Chief acquisition to approximately 796,000 MMBtu/d.

In April 2008, we commenced construction of an $80.0 million natural gas processing facility called Bear Creek in Hood County near our existing North Texas Assets. The new plant will have a gas processing capacity of 200 MMcf/d. Due to the recent decline in commodity prices and the corresponding decline in drilling activity, we do not anticipate that the additional processing capacity provided by the Bear Creek plant will be needed until late 2010 or in 2011. Therefore, we have decided to put this construction project on hold until the demand for this processing capacity returns, at which time we will seek to obtain financing for this project. As of December 31, 2008, we have spent approximately $20.2 million on this project for construction of a portion of the plant that will be utilized when the plant is completed in the future.

We have budgeted approximately $57.0 million for continued development of our north Texas assets during 2009. These capital projects represent system expansions that are planned to handle volume growth as well as projects required pursuant to existing obligations with producers to connect new wells to our gathering systems in north Texas. Several of our customers, including one of our largest customers in the Barnett Shale, have recently announced drilling plans for 2009 that are substantially below their drilling levels during 2008. As a result, our capital expenditures related to well connections during 2009 may be less than budgeted.

*North Louisiana Expansion Project.* In April 2007, we completed construction and commenced operations on our north Louisiana expansion, which is an extension of our LIG system designed to increase take-away pipeline capacity to the producers developing natural gas in the fields south of Shreveport, Louisiana. The north Louisiana expansion consists of approximately 63 miles of 24” mainline with 9 miles of 16” gathering lateral pipeline and 10,000 horsepower of new compression referred to as our Red River lateral. Our Red River lateral bisects the developing Haynesville Shale gas play in north Louisiana. The Red River lateral was operating at near capacity during 2008 so we added 35 MMcf/d of capacity by adding compression during the third quarter of 2008, bringing the total capacity of the Red River lateral to approximately 275 MMcf/d. As of December 31, 2008, the Red River lateral was flowing at approximately 225,000 MMBtu/d. Interconnects on the north Louisiana expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission and Trunkline Gas.

We have budgeted approximately $31.0 million for continued expansion in north Louisiana during 2009 with additional compression providing approximately 100 MMcf/d of increased capacity to producers in the Haynesville

Shale gas play. The expansion is scheduled to be completed in July 2009. We have 10 year firm transportation contracts subscribing to all the capacity on this project with four large producers.

**Other Developments**

*Issuance of Common Units.* On April 9, 2008, we issued 3,333,334 common units in a private offering at $30.00 per unit, which represented an approximate 7% discount from the market price. Net proceeds from the issuance, including the general partner contribution less expenses associated with the issuance, were approximately $102.0 million.

*Conversion of Subordinated and Senior Subordinated Series C Units.* The subordination period for the subordinated units owned by our general partner ended and the remaining 4,668,000 subordinated units converted into common units representing limited partner interests of the Partnership effective February 16, 2008.

The 12,829,650 senior subordinated series C units also converted into common units representing limited partner interests effective February 16, 2008. Our general partner owned 6,414,830 of the series C units that converted to common units.

*Senior Subordinated Series D Units.* On March 23, 2007, we issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests in a private offering. The senior subordinated series D units will convert to common units representing limited partner interests on March 23, 2009. Since we did not make distributions of available cash from operating surplus, as defined in the partnership agreement, of at least $0.62 per unit on each outstanding common unit for the quarter ending December 31, 2008 and did not generate adjusted operating surplus, as defined in the partnership agreement, of at least $0.62 per unit on each outstanding common unit for the quarter ending December 31, 2008, each senior subordinated series D unit will convert into 1.05 common units.

**Midstream Segment**

*Gathering, Processing and Transmission.* Our primary Midstream assets include our North Texas Assets, south Texas assets, Louisiana assets and Mississippi assets. These systems, in the aggregate, consist of over 5,700 miles of pipeline, 12 natural gas processing plants and four fractionators and contributed approximately 88.0% of our gross margin in both 2008 and 2007.

- *North Texas Assets.* On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale. The acquired systems included gathering pipeline, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that transaction, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system.
  - *Gathering System.* Since the date of the acquisition through December 31, 2008, we have connected 444 new wells to our north Texas gathering system and significantly increased the dedicated acreage owned by other producers. During May and July 2008, we completed the 29-mile expansion in north Johnson County to our north Texas gathering systems with a current gathering capacity of 235 MMcf/d which will be increased to 400 MMcf/d in April 2009 by adding compression. As of December 31, 2008, total capacity on our north Texas gathering system, including the north Johnson County expansion, was approximately 1,100 MMcf/d and total throughput was approximately 796,000 MMBtu/d.
  - *Processing Facilities.* Since 2006, we have constructed three gas processing plants with a total processing capacity in the Barnett Shale of 280 MMcf/d, including our Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, our Azle plant, which is a 50 MMcf/d cryogenic processing plant and our Goforth plant, which is a 30 MMcf/d processing plant. We have also installed two 40 gallon per minute and one 100 gallon per minute amine treating plants to provide carbon dioxide removal capability.

- *North Texas Pipeline (NTP).* We expanded our NTP system in the second quarter of 2007 to a total capacity of approximately 375 MMcf/d. The NTP will also interconnect with a new interstate pipeline that is being constructed by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing Pipeline, which is expected to provide our customers access to premium midwest and east coast markets.

- *South Texas Assets.* We have assembled a highly-integrated south Texas system comprised of approximately 1,400 miles of intrastate gathering and transmission pipelines, processing plants with a processing capacity of approximately 150 MMcf/d and a contract with a third party to process gas from our Vanderbilt system. The south Texas system was built through a number of acquisitions and follow-on organic projects, including acquisitions of the Gulf Coast system, the Corpus Christi system, the Gregory gathering system and processing plant, the Hallmark system and the Vanderbilt system. Average throughput on the system for the year ended December 31, 2008 was approximately 423,000 MMBtu/d, and average throughput for the Gregory and Vanderbilt processing assets was approximately 187,000 MMBtu/d. The system gathers gas from major production areas in the Texas Gulf Coast and delivers gas to the industrial markets, power plants, other pipelines and gas distribution companies in the region from Corpus Christi to the Houston area.

- *Louisiana Assets.* Our Louisiana assets include our LIG intrastate pipeline system and our gas processing and liquids business in south Louisiana, referred to as our south Louisiana processing assets.

  - *LIG System.* The LIG system is the largest intrastate pipeline system in Louisiana, consisting of approximately 2,000 miles of gathering and transmission pipeline, with an average throughput of approximately 960,000 MMBtu/d for the year ended December 31, 2008. The system also includes two operating, on-system processing plants, our Plaquemine and Gibson plants, with an average throughput of 311,000 MMBtu/d for the year ended December 31, 2008. The system has access to both rich and lean gas supplies. These supplies reach from north Louisiana to new onshore production in south central and southeast Louisiana. LIG has a variety of transportation and industrial sales customers, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans. In 2007, we extended our LIG system to the north to reach additional productive areas. This extension, referred to as the north Louisiana expansion or Red River lateral, consists of 63 miles of 24” mainline with 9 miles of gathering lateral pipeline and 10,000 horsepower of compression. Our Red River lateral bisects the developing Haynesville Shale gas play in north Louisiana. The Red River lateral was operating at near capacity during 2008 so we added 35 MMcf/d of capacity by adding compression during the third quarter of 2008 bringing the total capacity of the Red River lateral to approximately 275 MMcf/d. As of December 31, 2008, the Red River lateral was flowing at approximately 225,000 MMBtu/d.

  - *South Louisiana Processing Assets.* Natural gas processing capacity available to the Gulf Coast producers continues to exceed demand. During 2007 and 2008, we completed a number of operational changes at our Eunice facility and other plants to idle certain equipment, reduce operating expenses and reconfigure operations to manage the lower utilization. In addition, we have increased our focus on upstream markets and opportunities through integration of our LIG system and south Louisiana processing assets to improve our overall performance. In 2008, our south Louisiana assets were negatively impacted by hurricanes Gustav and Ike, which came ashore in September 2008. Most of the south Louisiana assets, other than the Sabine Pass processing plant, sustained minimal physical damage and promptly resumed operations. The repairs to the Sabine Pass processing plant were completed during the fourth quarter of 2008 and the plant returned to service in January 2009. In addition, several offshore platforms and pipelines owned by third parties transporting gas production to our Pelican, Eunice, Sabine Pass and Blue Water processing plants were damaged by the storms and repair to these offshore facilities continued during the fourth quarter of 2008. We anticipate that production levels will not recover to pre-hurricane levels until mid-2009, when all repairs are expected to be complete. The south Louisiana processing assets include the following:

    - *Eunice Processing Plant and Fractionation Facility.* The Eunice processing plant has a capacity of 1.2 Bcf/d and processed approximately 521,000 MMBtu/d for the year ended December 31, 2008. The plant is connected to onshore gas supply, as well as continental shelf and deepwater gas production and

has downstream connections to the ANR Pipeline, Florida Gas Transmission and Texas Gas Transmission, or TGT. TGT modified its system operations in early 2007 in a manner that significantly reduced the volumes available from TGT for processing at the Eunice plant. The Eunice fractionation facility, which was idled in August 2007, has a capacity of 36,000 Bbls/d of liquid products. Beginning in August 2007, the liquids from the Eunice processing plant were transported through our Cajun Sibon pipeline system to our Riverside plant for fractionation. If liquid volumes exceed Riverside's fractionation capacity, the liquids are delivered to a third party for fractionation. This operational change improved overall operating income because of operating cost reductions at the Eunice plant. The facility continues to maintain a truck unloading rack where approximately 10 trucks per day are unloaded and the raw make is sent to Riverside for fractionation. Eunice also has 190,000 Bbls of above-ground storage capacity. The Eunice fractionation facility, when operational, produces ethane, propane, iso-butane, normal butane and natural gasoline for various customers. The fractionation facility is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility.

- *Pelican Processing Plant.* The Pelican processing plant complex is located in Patterson, Louisiana and has a capacity of 600 MMcf/d of natural gas. For the year ended December 31, 2008, the plant processed approximately 266,000 MMBtu/d. The Pelican plant is connected with continental shelf and deepwater production and has downstream connections to the ANR Pipeline.
- *Sabine Pass Processing Plant.* The Sabine Pass processing plant is located east of the Sabine River at Johnson's Bayou, Louisiana and has a capacity of 300 MMcf/d of natural gas. The Sabine Pass processing plant is connected to continental shelf and deepwater gas production with downstream connections to Florida Gas Transmission, Tennessee Gas Pipeline (TGP) and Transco. For the first seven months of 2008, this facility was processing at full capacity. In early August 2008, the Sabine Pass processing plant sustained fire damage which occurred during an attempt to bring the plant back on line following a tropical storm. The plant was repaired and ready to return to service when it was hit by hurricanes Gustav and Ike in early September 2008. The plant has been repaired and was placed back in service in early January 2009.
- *Blue Water Gas Processing Plant.* We acquired a 23.85% interest in the Blue Water gas processing plant in the November 2005 El Paso acquisition and acquired an additional 35.42% interest in May 2006, at which time we became the operator of the plant. The plant has a net capacity to our interest of 186 MMcf/d. For the year ended December 31, 2008, this facility processed approximately 110,000 MMBtu/d net to our interest. The Blue Water plant is located near Crowley, Louisiana. The Blue Water facility is connected to continental shelf and deepwater production volumes through the Blue Water pipeline system. The facility also performs liquid natural gas (LNG) conditioning services for the Excelerate Energy LNG tanker unloading facility. Downstream connections from this plant include TGP and Columbia Gulf Transmission. During 2008, TGP acquired Columbia Gulf Transmission's ownership share in the Blue Water pipeline. In January 2009, TGP reversed the flow of the gas on the pipeline thereby removing access to all the gas processed at our Blue Water plant from the Blue Water offshore system and the plant is not currently in operation. At this time, we have not found alternative sources of new gas for the Blue Water plant but we will continue to look for new sources of gas, including the option of moving gas from our LIG system over to Blue Water plant. We do not expect to make a decision on any of these options for the Blue Water plant in the near term due to the excess processing capacity in the Gulf Coast and our restricted access to capital. The Blue Water plant contributed gross margin of $3.9 million and $4.2 million and incurred operating expenses of $1.2 million and $1.1 million for the years ended December 31, 2008 and 2007, respectively. We recognized an impairment of $17.8 million for the year ended December 31, 2008 related to the Blue Water plant because the plant was idled in January 2009. This impairment represents the carrying amount of the plant in excess of the estimated fair value of the plant as of December 31, 2008.
- *Riverside Fractionation Plant.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of 28,000 to 30,000 Bbls/d of liquids products and fractionates liquids delivered by the Cajun Sibon

pipeline system from our Eunice, Pelican, Blue Water and Cow Island plants or by truck. The Riverside facility has above-ground storage capacity of approximately 102,000 Bbls.

- *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of approximately 2.4 million Bbls of underground storage.
- *Cajun Sibon Pipeline System.* The Cajun Sibon pipeline system consists of approximately 400 miles of 6" and 8" pipelines with a system capacity of approximately 28,000 Bbls/d. The pipeline transports unfractionated NGLs, referred to as raw make, from the Eunice, Pelican and Blue Water plants to either the Riverside fractionator or the Napoleonville storage facility. Alternate deliveries can be made to the Eunice plant.

- *Mississippi Assets.* Our Mississippi assets include approximately 600 miles of natural gas gathering and transmission pipelines. The system gathers natural gas from producers, receives and delivers natural gas from and to several major interstate pipelines, including Sonat and Transco, and delivers gas to utilities and industrial end-users. The average system throughput was approximately 128,000 MMBtu/d for the year ended December 31, 2008.
- Other Midstream assets and activities include:
  - *Arkoma Gathering System.* This approximately 140 mile low-pressure gathering system in southeastern Oklahoma delivers gathered gas into a mainline transmission system. For the year ended December 31, 2008, throughput on the system averaged approximately 22,000 MMBtu/d. This gathering system was sold in February 2009 to an unrelated third party for approximately $11.0 million.
  - *East Texas.* Currently our east Texas system, made up of natural gas pipelines and compression installations, gathers and processes natural gas and delivers gas to NGPL, Regency Gas, and to other intrastate pipeline systems. For the year ended December 31, 2008, throughput on the system averaged approximately 42,000 MMBtu/d. We expanded this gas gathering system in May 2008 and it has a current capacity of 100 MMcf/d. We are expecting to receive our first delivery of Haynesville Shale gas into our east Texas system in the first quarter of 2009.
  - *Other.* Other Midstream assets consist of a variety of gathering lines and processing plants with a processing capacity of approximately 66 MMcf/d. Total volumes gathered and resold were approximately 16,000 MMBtu/d for the year ended December 31, 2008. Total volumes processed were approximately 16,000 MMBtu/d in the same period.
  - *Off-System Services.* We offer natural gas marketing services on behalf of producers of natural gas that is not gathered, transmitted, treated or processed by our assets. We market this gas on a number of interstate and intrastate pipelines. These volumes averaged approximately 85,000 MMBtu/d in 2008.

**Treating Segment**

We operate (or lease to producers for operation) treating plants that remove carbon dioxide and hydrogen sulfide from natural gas before it is delivered into transportation systems to ensure that it meets pipeline quality specifications. Our treating division contributed approximately 12.0% of our gross margin in both 2008 and 2007. At December 31, 2008, we had approximately 200 treating and dew point control plants in operation. Pipeline companies have begun enforcing gas quality specifications to lower the dew point of the gas they receive and transport. A higher relative dew point can sometimes cause liquid hydrocarbons to condense in the pipeline and cause operating problems and gas quality issues to the downstream markets. Hydrocarbon dew point plants are skid mounted process equipment that remove these hydrocarbons. Typically these plants use a Joules-Thompson expansion process to lower the temperature of the gas stream and collect the liquids before they enter the downstream pipeline. Our Treating division views dew point control as complementary to our treating business.

We believe we have the largest gas treating operation in the Texas and Louisiana gulf coast. Natural gas from certain formations in the Texas gulf coast, as well as other locations, is high in carbon dioxide, which generally needs to be removed before introduction of the gas into transportation pipelines. Many of our active plants are treating gas from the Wilcox and Edwards formations in the Texas gulf coast, both of which are deeper formations

that are high in carbon dioxide. In cases where producers pay us to operate the treating facilities, we either charge a fixed rate per Mcf of natural gas treated or charge a fixed monthly fee.

All of the shale reservoirs being developed today have concentrations of carbon dioxide above the normal pipeline quality specifications of 2.0%. The Haynesville Shale in northern Louisiana is still experiencing some robust development because of the higher success in completing these wells. We believe that our Treating business strategy is well suited to the producers in the Haynesville Shale especially during this time of relatively lower gas prices. The lower gas prices create an incentive for producers to use equipment supplied by others as opposed to buying their own equipment because it is more efficient use of their capital.

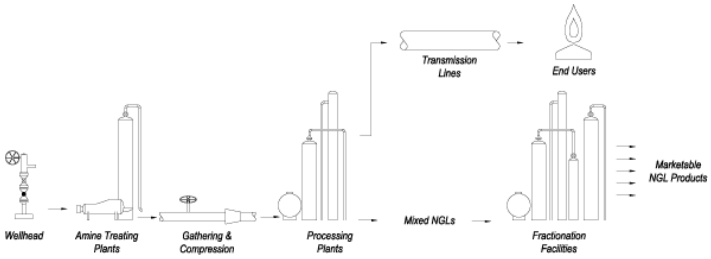
Our treating growth strategy is to utilize our existing fleet of amine plants to support our growth in the Haynesville Shale gas play. We believe our track record of reliability, current availability of equipment and our strategy of sourcing new equipment provide a significant advantage in competing for new treating business.

*Treating process.* The amine treating process involves a continuous circulation of a liquid chemical called amine that physically contacts with the natural gas. Amine has a chemical affinity for hydrogen sulfide and carbon dioxide that allows it to remove the impurities from the gas. After mixing, gas and reacted amine are separated and the impurities are removed from the amine by heating. Treating plants are sized by the amine circulation capacity in terms of gallons per minute.

*Sale of Interest in the Seminole Plant.* In November 2008, we sold our undivided 12.4% interest in the Seminole gas processing plant to an unrelated third party for $85.0 million and realized a gain on the sale of $49.8 million. We acquired our non-operating interest in this carbon dioxide processing plant in June 2003.

**Industry Overview**

The following diagram illustrates the natural gas treating, gathering, processing, fractionation and transmission process.




The midstream natural gas industry is the link between exploration and production of natural gas and the delivery of its components to end-use markets. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

*Natural gas gathering.* The natural gas gathering process follows the drilling of wells into gas bearing rock formations. Once a well has been completed, the well is connected to a gathering system. Gathering systems typically consist of a network of small diameter pipelines and, if necessary, compression systems that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission.

*Compression.* Gathering systems are operated at pressures that will maximize the total throughput from all connected wells. Because wells produce at progressively lower field pressures as they age, it becomes increasingly difficult to deliver the remaining production in the ground against the higher pressure that exists in the connected gathering system. Natural gas compression is a mechanical process in which a volume of gas at an existing pressure

is compressed to a desired higher pressure, allowing gas that no longer naturally flows into a higher-pressure downstream pipeline to be brought to market. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver gas into a higher-pressure downstream pipeline. If field compression is not installed, then the remaining natural gas in the ground will not be produced because it will be unable to overcome the higher gathering system pressure. In contrast, if field compression is installed, a declining well can continue delivering natural gas.

*Natural gas treating.* The composition of natural gas varies depending on the field the formation and reservoir from which it is produced. Natural gas from certain formations is high in carbon dioxide. Treating plants are placed at or near a well and remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced into gathering systems and transmission pipelines to ensure that it meets pipeline quality specifications.

*Natural gas processing.* The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of NGLs and contaminants, such as water, sulfur compounds, nitrogen or helium. Natural gas produced by a well may not be suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components and contaminants. Natural gas in commercial distribution systems is composed almost entirely of methane and ethane, with moisture and other contaminants removed to very low concentrations. Natural gas is processed not only to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas, but also to separate from the gas those hydrocarbon liquids that have higher value as NGLs. The removal and separation of individual hydrocarbons by processing is possible because of differences in weight, boiling point, vapor pressure and other physical characteristics. Natural gas processing involves the separation of natural gas into pipeline quality natural gas and a mixed NGL stream, as well as the removal of contaminants.

*NGL fractionation.* Fractionation is the process by which NGLs are further separated into individual, more valuable components. NGL fractionation facilitates separate mixed NGL streams into discrete NGL products: ethane, propane, isobutane, normal butane, natural gasoline and stabilized condensate. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating fuel, an engine fuel and industrial fuel. Isobutane is used principally to enhance the octane content of motor gasoline. Normal butane is used as a petrochemical feedstock in the production of ethylene and butylene (a key ingredient in synthetic rubber), as a blend stock for motor gasoline and to derive isobutene through isomerization. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is used primarily as motor gasoline blend stock or petrochemical feedstock.

*Natural gas transmission.* Natural gas transmission pipelines receive natural gas from mainline transmission pipelines, processing plants, and gathering systems and deliver it to industrial end-users, utilities and to other pipelines.

**Supply/Demand Balancing**

As we purchase natural gas, we establish a margin normally by selling natural gas for physical delivery to third party users. We can also use over-the-counter derivative instruments or enter into a future delivery obligation under futures contracts on the New York Mercantile Exchange. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is not to acquire and hold natural gas future contracts or derivative products for the purpose of speculating on price changes.

**Competition**

The business of providing gathering, transmission, treating, processing and marketing services for natural gas and NGLs is highly competitive. We face strong competition in obtaining natural gas supplies and in the marketing and transportation of natural gas and NGLs. Our competitors include major integrated oil companies, natural gas producers, interstate and intrastate pipelines and other natural gas gatherers and processors. Competition for natural gas supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. Many of

our competitors offer more services or have greater financial resources and access to larger natural gas supplies than we do. Our competition differs in different geographic areas.

Our gas treating operations face competition from manufacturers of new treating and dew point control plants and from a small number of regional operators that provide plants and operations similar to ours. We also face competition from vendors of used equipment that occasionally operate plants for producers. In addition, we routinely lose business to gas gatherers who have underutilized treating or processing capacity and can take the producers' gas without requiring wellhead treating. We may also lose wellhead treating opportunities to blending, which is a pipeline company's ability to waive quality specifications and allow producers to deliver their contaminated gas untreated. This is generally referred to as blending because of the receiving company's ability to blend this gas with cleaner gas in the pipeline such that the resulting gas meets pipeline specification.

In marketing natural gas and NGLs, we have numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil and gas companies, and local and national natural gas producers, gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases, engaged directly, and through affiliates, in marketing activities that compete with our marketing operations.

We face strong competition for acquisitions and development of new projects from both established and start-up companies. Competition increases the cost to acquire existing facilities or businesses, and results in fewer commitments and lower returns for new pipelines or other development projects. Many of our competitors have greater financial resources or lower capital costs, or are willing to accept lower returns or greater risks. Our competition differs by region and by the nature of the business or the project involved.

**Natural Gas Supply**

Our transmission pipelines have connections with major interstate and intrastate pipelines, which we believe have ample supplies of natural gas in excess of the volumes required for these systems. In connection with the construction and acquisition of our gathering systems, we evaluate well and reservoir data publicly available or furnished by producers or other service providers to determine the availability of natural gas supply for the systems and/or obtain a minimum volume commitment from the producer that results in a rate of return on our investment. Based on these facts, we believe that there should be adequate natural gas supply to recoup our investment with an adequate rate of return. We do not routinely obtain independent evaluations of reserves dedicated to our systems due to the cost and relatively limited benefit of such evaluations. Accordingly, we do not have estimates of total reserves dedicated to our systems or the anticipated life of such producing reserves.

**Credit Risk and Significant Customers**

We are diligent in attempting to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of gas exposes us to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to our overall profitability.

During the year ended December 31, 2008, we had one customer that accounted for approximately 11.0% of our consolidated revenues. While this customer represents a significant percentage of consolidated revenues, the loss of this customer would not have a material impact on our results of operations.

**Regulation**

*Regulation by FERC of Interstate Natural Gas Pipelines.* We do not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or FERC, does not directly regulate our operations under the National Gas Act, or NGA. However, FERC's regulation of interstate natural gas pipelines influences certain aspects of our business and the market for our products. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce and its authority to regulate those services includes:

- the certification and construction of new facilities;

- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- maximum rates payable for certain services; and
- the initiation and discontinuation of services.

While we do not own any interstate pipelines, we do transport some gas in interstate commerce. The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. In addition, FERC has adopted, or is in the process of adopting, various regulations concerning natural gas market transparency that will apply to some of our pipeline operations. The maximum rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate", as defined in the NGPA. The rates are generally subject to review every three years by FERC or by an appropriate state agency. Rates for interstate services provided under NGPA Section 311 on our NTP and Mississippi systems are currently under review. The filed rates, which are based on the respective system's cost of service and constitute the maximum rates that can be charged on those systems for interstate service, are slightly lower than the rates previously charged. Rate reviews on our Louisiana and south Texas pipeline systems are scheduled for March and April 2009, respectively.

*Intrastate Pipeline Regulation.* Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

*Gathering Pipeline Regulation.* Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC under the NGA. We own a number of natural gas pipelines that we believe meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

We are subject to some state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply.

*Sales of Natural Gas.* The price at which we sell natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect less extensive regulation. We cannot predict the ultimate impact of these regulatory changes on our natural gas marketing operations but we do not believe that we will be affected by any such FERC action materially differently than other natural gas marketers with whom we compete.

**Environmental Matters**

*General.* Our operation of treating, processing and fractionation plants, pipelines and associated facilities in connection with the gathering, treating and processing of natural gas and the transportation, fractionation and storage of NGLs is subject to stringent and complex federal, state and local laws and regulations relating to release

of hazardous substances or wastes into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall costs of doing business, including cost of planning, constructing, and operating plants, pipelines, and other facilities. Included in our construction and operation costs are capital cost items necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon any future acquisition of operating assets.

Any failure to comply with applicable environmental laws and regulations, including those relating to equipment failures and obtaining required governmental approvals, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in less common circumstances, issuance of injunctions or construction bans or delays. We believe that we currently hold all material governmental approvals required to operate our major facilities. As part of the regular overall evaluation of our operations, we have implemented procedures to review and update governmental approvals as necessary. We believe that our operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on our operating results or financial condition.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Moreover, risks of process upsets, accidental releases or spills are associated with our possible future operations, and we cannot assure you that we will not incur significant costs and liabilities, including those relating to claims for damage to property and persons as a result of any such upsets, releases, or spills. In the event of future increases in environmental costs, we may be unable to pass on those cost increases to our customers. A discharge of hazardous substances or wastes into the environment could, to the extent losses related to the event are not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and to pay fines or penalties that may be assessed and the cost related to claims made by neighboring landowners and other third parties for personal injury or damage to property. We will attempt to anticipate future regulatory requirements that might be imposed and plan accordingly to comply with changing environmental laws and regulations and to minimize costs.

*Hazardous Substance and Waste.* To a large extent, the environmental laws and regulations affecting our possible future operations relate to the release of hazardous substances or solid wastes into soils, groundwater and surface water, and include measures to prevent and control pollution. These laws and regulations generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous wastes, and may require investigatory and corrective actions at facilities where such waste may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the "Superfund" law, and comparable state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to a release of "hazardous substance" into the environment. Potentially liable persons include the owner or operator of the site where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the potentially responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment. Although "petroleum" as well as natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of future, ordinary operations, we may generate wastes that may fall within the definition of a "hazardous substance." However, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, we may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such wastes have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state laws.

We also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the Federal Resource Conservation and Recovery Act, or FRCRA, and comparable state

statutes. We are not currently required to comply with a substantial portion of the FRCRA requirements because our operations generate minimal quantities of hazardous wastes. From time to time, the Environmental Protection Agency, or EPA, has considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. Moreover, it is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Changes in applicable regulations may result in an increase in our capital expenditures or plant operating expenses.

We currently own or lease, and have in the past owned or leased, and in the future we may own or lease, properties that have been used over the years for natural gas gathering, treating or processing and for NGL fractionation, transportation or storage. Solid waste disposal practices within the NGL industry and other oil and natural gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, some hydrocarbons and other solid wastes have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom we had no control as to such entities' handling of hydrocarbons or other wastes and the manner in which such substances may have been disposed of or released. These properties and wastes disposed thereon may be subject to CERCLA, FRCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination, or to take action to prevent future contamination.

We acquired our south Louisiana processing assets from El Paso in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. We have completed the remediation work on this site pending the final review and approval of our reports by LDEQ. As of December 31, 2008, we had incurred approximately $0.5 million in such remediation costs. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

We acquired LIG Pipeline Company, and its subsidiaries, on April 1, 2004 from American Electric Power Company (AEP). Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. AEP has indemnified us 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. This remediation work is nearing completion. We do not expect to incur any material liability associated with this site; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations.

We acquired assets from Duke Energy Field Services, L.P. (DEFS) in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations had been identified at levels that exceeded the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase and sale agreement, DEFS retained the liability for cleanup of the Conroe site. Moreover, DEFS has entered into an agreement with a third party company pursuant to which the remediation costs associated with the Conroe site have been assumed by this third party company that specializes in remediation work. We do not expect to incur any material liability associated with this site; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations.

*Air Emissions.* Our current and future operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and impose various monitoring and reporting requirements. Pursuant to these laws and regulations, we may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing

air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air-emission related issues. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties, and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition or operating results, and the requirements are not expected to be more burdensome to us than any similarly situated company.

*Climate Change.* In response to concerns suggesting that emissions of certain gases, commonly referred to as "greenhouse gases" (including carbon dioxide and methane), may be contributing to warming of the Earth's atmosphere, the U.S. Congress is actively considering legislation to reduce such emissions. In addition, at least one-third of the states, either individually or through multi-state regional initiatives, have already taken legal measures intended to reduce greenhouse gas emissions, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs. The EPA is separately considering whether it will regulate greenhouse gases as "air pollutants" under the existing federal Clean Air Act. Passage of climate change legislation or other federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which we conduct business could adversely affect the demand for the products we store, transport, and process, and depending on the particular program adopted could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. We may be unable to recover any such lost revenues or increased costs in the rates we charge our customers, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have adverse effects on our business, financial position, results of operations and prospects.

*Clean Water Act.* The Federal Water Pollution Control Act, also known as the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including natural gas liquid related wastes, into state waters or waters of the United States. Regulations promulgated pursuant to these laws require that entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System, or NPDES, and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess administrative, civil and criminal penalties for discharges of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff. We believe that we are in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that continued compliance with such existing permit conditions will not have a material effect on our results of operations.

*Employee Safety.* We are subject to the requirements of the Occupational Safety and Health Act, referred to as OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

*Safety Regulations.* Our pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, as amended, or HLPSA, and the Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192, effective February 14, 2004 relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA covers crude oil, carbon dioxide, NGL and petroleum products pipelines and requires any entity which owns or operates pipeline facilities to comply with the regulations under the HLPSA, to permit access

to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. The Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192 (PIM) requires operators of gas transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. In addition, the Railroad Commission of Texas, or TRRC, regulates our pipelines in Texas under its own pipeline integrity management rules. The Texas rule includes certain transmission and gathering lines based upon pipeline diameter and operating pressures. We believe that our pipeline operations are in substantial compliance with applicable HLPSA and PIM requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the HLPSA or PIM requirements will not have a material adverse effect on our results of operations or financial positions.

**Office Facilities**

We occupy approximately 95,400 square feet of space at our executive offices in Dallas, Texas under a lease expiring in June 2014, approximately 25,100 square feet of office space for our south Louisiana operations in Houston, Texas with lease terms expiring in January 2013 and approximately 11,800 square feet of office space for our North Texas operations in Fort Worth, Texas with lease terms expiring in April 2013.

During 2008 the Partnership leased approximately 115,000 square feet of additional office space at 2828 N. Harwood Street, Dallas, Texas. This space was intended to accommodate the corporate office expansion required by the continued growth of the business. Due to the economic downturn in the fourth quarter of 2008, it was determined the relocation of the corporate offices would not take place and the lease, which was originally set up to run through January 2012, was terminated on December 29, 2008 with an effective termination date of January 2010. A portion of this leased space is currently occupied by our computer hardware and will continue to be occupied through December 2009.

**Employees**

As of December 31, 2008, we (through our Operating Partnership) employed approximately 780 full-time employees. Approximately 270 of our employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. We are not party to any collective bargaining agreements, and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

**Item 1A.** ***Risk Factors***

*The following risk factors and all other information contained in this report should be considered carefully when evaluating us. These risk factors could affect our actual results. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. If any of the following risks occur, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included herein.*

**Risks Inherent In Our Business**

***We may not be able to obtain funding or obtain funding on acceptable terms because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.***

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile, which has caused a substantial deterioration in the credit and capital markets. These conditions, along with significant write-offs in the financial services sector and the re-pricing of credit risk, have made, and will likely continue to make, it difficult to obtain funding for our capital needs.

Beginning in the second half of 2008, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets has diminished significantly. In particular, as a result of concerns about the stability of financial markets generally and the solvency of lending counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to borrowers' current debt and reduced and, in some cases, ceased to provide funding to borrowers.

Due to these factors, we cannot be certain that new debt or equity financing will be available to us on acceptable terms or at all. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due. Moreover, without adequate funding, we may be unable to execute our growth strategy, complete future acquisitions or future construction projects or other capital expenditures, take advantage of other business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations. Further, our customers may increase collateral requirements from us or reduce the business they transact with us to reduce their credit exposure to us.

***Due to current economic conditions, our ability to obtain funding under our bank credit facility could be impaired.***

We operate in a capital-intensive industry and rely on our bank credit facility to finance a significant portion of our capital expenditures. Our ability to borrow under our bank credit facility may be impaired because of the recent downturn in the financial markets, including issues surrounding the solvency of many institutional lenders and recent failures of several banks.

Specifically, we may be unable to obtain adequate funding under our bank credit facility because:

- one or more of our lenders may be unable or otherwise fail to meet its funding obligations;
- the lenders do not have to provide funding if there is a default under the credit agreement or if any of the representations or warranties included in the agreement are false in any material respect; and
- if any lender refuses to fund its commitment for any reason, whether or not valid, the other lenders are not required to provide additional funding to make up for the unfunded portion.

On February 27, 2009, we entered into an amendment to our bank credit facility, revising certain financial and other restrictive covenants under this facility through its maturity date. See Item 1, "Business—Amendments to Credit Documents." There can be no assurance that we will be able to comply with any newly-negotiated covenants in the future or that we will be able to obtain waivers or amendments of these covenants in the event of future noncompliance. If we are not in compliance with these covenants, and if we are unable to secure necessary waivers or other amendments from the counterparties, we will not have access to our bank credit facility, which could significantly affect our ability to meet our expenses and operate our business. Further, such noncompliance could cause a default under the bank credit facility, which could result in acceleration of our outstanding debt.

If we are unable to access funds under our bank credit facility, we will need to meet our capital requirements, including some of our short-term capital requirements, using other sources. Due to current economic conditions, alternative sources of liquidity may not be available on acceptable terms, if at all. If the cash generated from our operations or the funds we are able to obtain under our bank credit facility or other sources of liquidity are not sufficient to meet our capital requirements, then we may need to delay or abandon capital projects or other business opportunities, which could have a material adverse effect on our results of operations and financial condition. Furthermore, if the current pressures on credit continue or worsen, we may not be able to refinance our then-outstanding debt or replace our then-outstanding letters of credit when due, which could have a material adverse effect on our business.

***We will not be able to pay cash distributions until our financial condition improves.***

Our bank credit facility and senior secured note agreement contain covenants which limit our ability to make distributions to unitholders so long as we do not meet certain financial ratios and tests. Under the amended bank

credit facility and senior secured note agreement, we may not make quarterly distributions to our unitholders unless the PIK notes have been repaid and the leverage ratio, as defined in the agreements, is less than 4.25 to 1.00. If the leverage ratio is between 4.00 to 1.00 and 4.25 to 1.00, we may make the minimum quarterly distribution of up to $0.25 per unit if the PIK notes have been repaid. If the leverage ratio is less than 4.00 to 1.00, we may make quarterly distributions to unitholders from available cash as provided by our partnership agreement if the PIK notes have been repaid. The PIK notes are due six months after the earlier of the refinancing or maturity of our bank credit facility. In order to repay the PIK notes prior to their scheduled maturity, we will need to amend or refinance our bank credit facility. Based on the amended provisions in our amended bank credit facility and senior secured note agreement, our current anticipated cash flows for 2009 and current economic conditions, we do not currently expect to be able to pay distributions to our unitholders in 2009 other than the distribution paid in February 2009 related to fourth quarter 2008 operating results. Even if we do not pay a distribution to unitholders, our unitholders may be liable for taxes on their share of our taxable income. See "— Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us."

In addition, even if our credit documents do not prohibit us from making distributions, we still may not have sufficient available cash each quarter to pay distributions to unitholders. Under the terms of our partnership agreement, we must pay our general partner's fees and expenses and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas transported in our gathering and transmission pipelines;
- the level of our processing and treating operations;
- the fees we charge and the margins we realize for our services;
- the price of natural gas;
- the relationship between natural gas and NGL prices;
- our level of operating costs; and
- restrictions on distributions contained in our bank credit facility.

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

- the level of capital expenditures we make;
- the cost of acquisitions, if any;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to make working capital borrowings under our bank credit facility to pay distributions;
- prevailing economic conditions; and
- the amount of cash reserves established by our general partner in its sole discretion for the proper conduct of our business.

Because of these factors, even if our credit documents do not prohibit us from making distributions, we still may not be able, or may not have sufficient available cash to pay distributions to unitholders each quarter. Furthermore, you should also be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

***Our profitability is dependent upon prices and market demand for natural gas and NGLs, which are beyond our control and have been volatile.***

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. A large percentage of our processing fees are realized under percent of liquids (POL) contracts that are directly impacted by the market price of NGLs. We also realize processing gross margins under fractionation margin (margin) contracts. These settlements are impacted by the relationship between NGL prices and the underlying natural gas prices, which is also referred to as the fractionation spread.

A significant volume of inlet gas at our south Louisiana and north Texas processing plants is settled under POL agreements. The POL fees are denominated in the form of a share of the liquids extracted and we are not responsible for the fuel or shrink associated with processing. Therefore, fee revenue under a POL agreement is directly impacted by NGL prices, and the decline of these prices in 2008 contributed to a significant decline in our gross margin from processing. We have a number of margin contracts on our Plaquemine and Gibson processing plants that expose us to the fractionation spread. Under these margin contracts our gross margin is based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state and the cost of fuel to extract during processing. During the last half of 2008, the fractionation spread narrowed significantly as the value of NGLs decreased more than the value of the gas and fuel associated with the processed gas. Thus the gross margin realized under these margin contracts was negatively impacted due to the commodity price environment. The significant decline in crude oil prices and a related decline in NGL prices during the last half of 2008 had a significant negative impact on our margins, and may negatively impact our gross margin further if such declines continue.

In the past, the prices of natural gas and NGLs have been extremely volatile and we expect this volatility to continue. For example, in 2007, the NYMEX settlement price for natural gas for the prompt month contract ranged from a high of $7.59 per MMBtu to a low of $5.43 per MMBtu. In 2008, the same index ranged from $6.46 per MMBtu to $13.10 per MMBtu. A composite of the OPIS Mt. Belvieu monthly average liquids price based upon our average liquids composition in 2007 ranged from a high of approximately $1.58 per gallon to a low of approximately $0.92 per gallon. In 2008, the same composite ranged from approximately $2.01 per gallon to approximately $0.56 per gallon.

We may not be successful in balancing our purchases and sales. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

The markets and prices for residue gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which fluctuates with changes in market and economic conditions and other factors, including:

- the impact of weather on the demand for oil and natural gas;
- the level of domestic oil and natural gas production;
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil, natural gas and NGLs;
- international demand for oil and NGLs;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability of downstream NGL fractionation facilities;

- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Changes in commodity prices may also indirectly impact our profitability by influencing drilling activity and well operations, and thus the volume of gas we gather and process. This volatility may cause our gross margin and cash flows to vary widely from period to period. Our hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of our throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in "— Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income." For a discussion of our risk management activities, please read Item 7A, "Quantitative and Qualitative Disclosures about Market Risk."

***Due to our lack of asset diversification, adverse developments in our gathering, transmission, treating, processing and producer services businesses would materially impact our financial condition.***

We rely exclusively on the revenues generated from our gathering, transmission, treating, processing and producer services businesses, and as a result our financial condition depends upon prices of, and continued demand for, natural gas and NGLs. Due to our lack of asset diversification, an adverse development in one of these businesses would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

***Many of our customers' drilling activity levels and spending for transportation on our pipeline system or gathering and processing at our facilities may be impacted by the current deterioration in the credit markets.***

Many of our customers finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of our customers' equity values have substantially declined. Adverse price changes, coupled with the overall downturn in the economy and the constrained capital markets, put downward pressure on drilling budgets for gas producers which could result in lower volumes being transported on our pipeline and gathering systems and processing through our processing plants. We have seen a decline in drilling activity by gas producers in our areas of operation during the fourth quarter of 2008. In addition, industry drilling rig count surveys published in early 2009 show substantial declines in rigs in operation as compared to 2008. Several of our customers, including one of our largest customers in the Barnett Shale, have recently announced drilling plans for 2009 that are substantially below their drilling levels during 2008. A significant reduction in drilling activity could have a material adverse effect on our operations.

***We are exposed to the credit risk of our customers and counterparties, and a general increase in the nonpayment and nonperformance by our customers could have an adverse effect on our financial condition and results of operations.***

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders. Many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of our customers' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and ability to make payment or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us.

***Our use of derivative financial instruments does not eliminate our exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduce our income.***

Our operations expose us to fluctuations in commodity prices, and our bank credit facility exposes us to fluctuations in interest rates. We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions and interest rate swaps with financial institutions. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices and interest rates. We have hedged only portions of our variable-rate debt and expected natural gas supply, NGL production and natural gas requirements. We continue to have direct interest rate and commodity price risk with respect to the unhedged portions. In addition, to the extent we hedge our commodity price and interest rate risks using swap instruments, we will forego the benefits of favorable changes in commodity prices or interest rates.

Even though monitored by management, our hedging activities may fail to protect us and could reduce our earnings and cash flow. Our hedging activity may be ineffective or adversely affect cash flow and earnings because, among other factors:

- hedging can be expensive, particularly during periods of volatile prices;
- our counterparty in the hedging transaction may default on its obligation to pay or otherwise fail to perform; and
- available hedges may not correspond directly with the risks against which we seek protection. For example:
  - the duration of a hedge may not match the duration of the risk against which we seek protection;
  - variations in the index we use to price a commodity hedge may not adequately correlate with variations in the index we use to sell the physical commodity (known as basis risk); and
  - we may not produce or process sufficient volumes to cover swap arrangements we enter into for a given period. If our actual volumes are lower than the volumes we estimated when entering into a swap for the period, we might be forced to satisfy all or a portion of our derivative obligation without the benefit of cash flow from our sale or purchase of the underlying physical commodity, which could adversely affect our liquidity.

Our financial statements may reflect gains or losses arising from exposure to commodity prices or interest rates for which we are unable to enter into fully economically effective hedges. In addition, the standards for cash flow hedge accounting are rigorous. Even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective cash flow hedges for accounting purposes. Our earnings could be subject to increased volatility to the extent our derivatives do not continue to qualify as cash flow hedges, and, if we assume derivatives as part of an acquisition, to the extent we cannot obtain or choose not to seek cash flow hedge accounting for the derivatives we assume. Please read Item 7A, “Quantitative and Qualitative Disclosures about Market Risk,” for a summary of our hedging activities.

***We must continually compete for natural gas supplies, and any decrease in our supplies of natural gas could adversely affect our financial condition and results of operations.***

If we are unable to maintain or increase the throughput on our systems by accessing new natural gas supplies to offset the natural decline in reserves, our business and financial results could be materially, adversely affected. In addition, our future growth will depend, in part, upon whether we can contract for additional supplies at a greater rate than the rate of natural decline in our currently connected supplies.

In order to maintain or increase throughput levels in our natural gas gathering systems and asset utilization rates at our treating and processing plants, we must continually contract for new natural gas supplies. We may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity near our gathering systems. Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural

gas reserves. For example, as oil and natural gas prices have recently decreased, there has been a corresponding decrease in drilling activity. Tax policy changes could also have a negative impact on drilling activity, reducing supplies of natural gas available to our systems. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in natural gas production or in the level of drilling activity in our principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position.

***We are vulnerable to operational, regulatory and other risks associated with our assets including, with respect to south Louisiana and the Gulf of Mexico assets, the effects of adverse weather conditions such as hurricanes.***

Our operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because we have a significant portion of our assets located in south Louisiana and the Gulf of Mexico. In the third and fourth quarters of 2008, our business was negatively impacted by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September. Although the majority of our assets in Texas and Louisiana sustained minimal physical damage from these hurricanes and promptly resumed operations, several offshore production platforms and pipelines owned by third parties that transport gas production to our Pelican, Eunice, Sabine Pass and Blue Water processing plants in south Louisiana were damaged by the storms. Some of the repairs to these offshore facilities were completed during the fourth quarter of 2008, but we do not anticipate that gas production to our south Louisiana plants will recover to pre-hurricane levels until mid-2009, when all repairs are expected to be complete. Additionally, one of our south Louisiana processing plants, the Sabine Pass processing plant, which is located on the shoreline of the Louisiana Gulf Coast, sustained some physical damage. The Sabine Pass processing plant was repaired during the fourth quarter of 2008 and the plant was returned to service in early January 2009. Our operations in north Texas were also impacted by these hurricanes because operations at Mt. Belvieu, Texas, a central distribution point for NGL sales where several fractionators are located which fractionate NGLs from the entire United States, were interrupted as a result of these storms. These storms resulted in an adverse impact to our gross margin of approximately $22.9 million in the last half of 2008.

Our concentration of activity in Louisiana and the Gulf of Mexico makes us more vulnerable than many of our competitors to the risks associated with these areas, including:

- adverse weather conditions, including hurricanes and tropical storms;
- delays or decreases in production, the availability of equipment, facilities or services; and
- changes in the regulatory environment.

Because a significant portion of our operations could experience the same condition at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other midstream companies who have operations in more diversified geographic areas.

In addition, our operations in south Louisiana are dependent upon continued conventional and deep shelf drilling in the Gulf of Mexico. The deep shelf in the Gulf of Mexico is an area that has had limited historical drilling activity. This is due, in part, to its geological complexity and depth. Deep shelf development is more expensive and inherently more risky than conventional shelf drilling. A decline in the level of deep shelf drilling in the Gulf of Mexico could have an adverse effect on our financial condition and results of operations.

***A substantial portion of our assets is connected to natural gas reserves that will decline over time, and the cash flows associated with those assets will decline accordingly.***

A substantial portion of our assets, including our gathering systems and our treating plants, is dedicated to certain natural gas reserves and wells for which the production will naturally decline over time. Accordingly, our cash flows associated with these assets will also decline. If we are unable to access new supplies of natural gas either by connecting additional reserves to our existing assets or by constructing or acquiring new assets that have access to additional natural gas reserves, our cash flows may decline.

***Growing our business by constructing new pipelines and processing and treating facilities subjects us to construction risks, risks that natural gas supplies will not be available upon completion of the facilities and risks of construction delay and additional costs due to obtaining rights-of-way and complying with local ordinances.***

One of the ways we intend to grow our business is through the construction of additions to our existing gathering systems and construction of new pipelines and gathering, processing and treating facilities. The construction of pipelines and gathering, processing and treating facilities requires the expenditure of significant amounts of capital, which may exceed our expectations. Generally, we may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. We may also rely on estimates of proved reserves in our decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, we face the risks of construction delay and additional costs due to obtaining rights-of-way and local permits and complying with city ordinances, particularly as we expand our operations into more urban, populated areas such as the Barnett Shale.

***Acquisitions typically increase our debt and subject us to other substantial risks, which could adversely affect our results of operations.***

From time to time, we may evaluate and seek to acquire assets or businesses that we believe complement our existing business and related assets. We may acquire assets or businesses that we plan to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of recently acquired businesses or assets;
- the diversion of management's attention from other business concerns;
- the loss of customers or key employees from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

Management's assessment of these risks is necessarily inexact and may not reveal or resolve all existing or potential problems associated with an acquisition. Realization of any of these risks could adversely affect our operations and cash flows. If we consummate any future acquisition, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Additionally, our ability to grow our asset base in the near future through acquisitions will be limited due to our lack of access to capital markets and due to restrictions under our borrowing agreements.

***We expect to encounter significant competition in any new geographic areas into which we seek to expand and our ability to enter such markets may be limited.***

If we expand our operations into new geographic areas, we expect to encounter significant competition for natural gas supplies and markets. Competitors in these new markets will include companies larger than us, which have both lower capital costs and greater geographic coverage, as well as smaller companies, which have lower total cost structures. As a result, we may not be able to successfully develop acquired assets and markets located in new geographic areas and our results of operations could be adversely affected.

***We may not be able to retain existing customers or acquire new customers, which would reduce our revenues and limit our future profitability.***

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other pipelines, and the price of, and demand for, natural gas in the markets we serve.

For the year ended December 31, 2008, approximately 46.0% of our sales of gas which were transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

***We depend on certain key customers, and the loss of any of our key customers could adversely affect our financial results.***

We derive a significant portion of our revenues from contracts with key customers. To the extent that these and other customers may reduce volumes of natural gas purchased under existing contracts, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers. Several of our customers, including one of our largest customers in the Barnett Shale, have recently announced drilling plans for 2009 that are substantially below their drilling levels during 2008. Agreements with key customers provide for minimum volumes of natural gas that each customer must purchase until the expiration of the term of the applicable agreement, subject to certain force majeure provisions. Customers may default on their obligations to purchase the minimum volumes required under the applicable agreements.

***Our business involves many hazards and operational risks, some of which may not be fully covered by insurance.***

Our operations are subject to the many hazards inherent in the gathering, compressing, treating and processing of natural gas and storage of residue gas, including:

- damage to pipelines, related equipment and surrounding properties caused by hurricanes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction and farm equipment;
- leaks of natural gas, NGLs and other hydrocarbons; and
- fires and explosions.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. Our operations are concentrated in Texas, Louisiana and the Mississippi Gulf Coast, and a natural disaster or other hazard affecting this region could have a material adverse effect on our operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. Our business interruption insurance covers only our Gregory processing plant. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

***The threat of terrorist attacks has resulted in increased costs, and future war or risk of war may adversely impact our results of operations and our ability to raise capital.***

Terrorist attacks or the threat of terrorist attacks cause instability in the global financial markets and other industries, including the energy industry. Uncertainty surrounding retaliatory military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, and the possibility that infrastructure facilities, including pipelines, production facilities, and transmission and distribution facilities, could be direct targets, or indirect casualties, of an act of terror. Instability in the financial markets as a result of terrorism, the war in Iraq or future developments could also affect our ability to raise capital.

Changes in the insurance markets attributable to the threat of terrorist attacks have made certain types of insurance more difficult for us to obtain. Our insurance policies now generally exclude acts of terrorism. Such insurance is not available at what we believe to be acceptable pricing levels. A lower level of economic activity could also result in a decline in energy consumption, which could adversely affect our revenues or restrict our future growth.

***Federal, state or local regulatory measures could adversely affect our business.***

While the FERC generally does not regulate our operations, it influences certain aspects of our business and the market for our products. The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC regulation under the Section 311 of the NGPA. Not only are our intrastate natural gas pipeline operations subject to limited rate regulation by FERC, but they are also subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that our rates for Section 311 transportation service or intrastate transportation service should be lowered, our business could be adversely affected.

Our natural gas gathering activities generally are exempt from FERC regulation under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC and the courts. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels since FERC has less extensively regulated the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Other state and local regulations also affect our business. We are subject to some ratable take and common purchaser statutes in the states where we operate. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport natural gas. Federal law leaves any economic regulation of natural gas gathering to the states, and some of the states in which we operate have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which we operate that have adopted some form of complaint-based regulation, like Oklahoma and Texas, generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination.

The states in which we conduct operations administer federal pipeline safety standards under the Pipeline Safety Act of 1968. The “rural gathering exemption” under the Natural Gas Pipeline Safety Act of 1968 presently exempts substantial portions of our gathering facilities from jurisdiction under that statute, including those portions located outside of cities, towns, or any area designated as residential or commercial, such as a subdivision or shopping center. The “rural gathering exemption,” however, may be restricted in the future, and it does not apply to

our natural gas transmission pipelines. In response to recent pipeline accidents in other parts of the country, Congress and the Department of Transportation, or DOT, have passed or are considering heightened pipeline safety requirements.

Compliance with pipeline integrity regulations issued by the United States Department of Transportation in December of 2003 or those issued by the TRRC could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately at $3.2 million, $1.2 million, and $1.1 million for the years ended December 31, 2008, 2007, and 2006, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $3.6 million during 2009. If our pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then we may be required to repair or replace sections of such pipelines, the cost of which cannot be estimated at this time.

As the Partnership's operations continue to expand into and around urban, or more populated areas, such as the Barnett Shale, it may incur additional expenses to mitigate noise, odor and light that may be emitted in our operations, and expenses related to the appearance of its facilities. Municipal and other local or state regulations are imposing various obligations, including, among other things, regulating the location of the Partnership's facilities, imposing limitations on the noise levels of its facilities and requiring certain other improvements that increase the cost of its facilities. The Partnership is also subject to claims by neighboring landowners for nuisance related to the construction and operation of its facilities, which could subject it to damages for declines in neighboring property values due to its construction and operation of facilities.

***Our business involves hazardous substances and may be adversely affected by environmental regulation.***

Many of the operations and activities of our gathering systems, plants and other facilities, including our south Louisiana processing assets, are subject to significant federal, state and local environmental laws and regulations. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from our facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Strict, joint and several liability may be incurred under these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties through which our gathering systems pass, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or releases of contaminants or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in our business due to our handling of natural gas and other petroleum products, air emissions related to our operations, historical industry operations, waste disposal practices and the prior use of natural gas flow meters containing mercury. In addition, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary. We may incur material environmental costs and liabilities. Furthermore, our insurance may not provide sufficient coverage in the event an environmental claim is made against us.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability.

***Our success depends on key members of our management, the loss or replacement of whom could disrupt our business operations.***

We depend on the continued employment and performance of the officers of the general partner of our general partner and key operational personnel. The general partner of our general partner has entered into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, our business operations could be materially adversely affected. We do not maintain any "key man" life insurance for any officers.

**Risk Inherent In An Investment In the Partnership**

***Crosstex Energy, Inc. controls our general partner and owned a 34% limited partner interest in us as of December 31, 2008. Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor its own interests.***

As of December 31, 2008, Crosstex Energy, Inc. indirectly owned an aggregate limited partner interest of approximately 34% in us. In addition, CEI owns and controls our general partner. Due to its control of our general partner and the size of its limited partner interest in us, CEI effectively controls all limited partnership decisions, including any decisions related to the removal of our general partner. Conflicts of interest may arise in the future between CEI and its affiliates, including our general partner, on the one hand, and our partnership, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates over our interests. These conflicts include, among others, the following situations:

*Conflicts Relating to Control*

- our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without these limitations, constitute breaches of fiduciary duty by our general partner;
- in resolving conflicts of interest, our general partner is allowed to take into account the interests of parties in addition to unitholders, which has the effect of limiting its fiduciary duties to the unitholders;
- our general partner's affiliates may engage in limited competition with us;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- in some instances our general partner may cause us to borrow funds from affiliates of the general partner or from third parties in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on our subordinated units or to make incentive distributions or hasten the expiration of the subordination period; and
- our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution.

*Conflicts Relating to Costs:*

- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional limited partner interests and reserves, each of which can affect the amount of cash that is available for the payment of principal and interest on the notes;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us; and

- our general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf.

***Our unitholders have no right to elect our general partner or the directors of its general partner and have limited ability to remove our general partner.***

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or the board of directors of its general partner and have no right to elect our general partner or the board of directors of its general partner on an annual or other continuing basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The general partner generally may not be removed except upon the vote of the holders of $66^{2}/_{3}\%$ of the outstanding units voting together as a single class. Because affiliates of the general partner controlled approximately 34% of all the units as of December 31, 2008, the general partner could not be removed without the consent of the general partner and its affiliates.

Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud, gross negligence, or willful or wanton misconduct in its capacity as our general partner. Cause does not include, in most cases, charges of poor management of the business, so the removal of the general partner because of the unitholders' dissatisfaction with the general partner's performance in managing our partnership will most likely result in the termination of the subordination period.

In addition, unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner's general partner, cannot be voted on any matter. In addition, the partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

As a result of these provisions, it will be more difficult for a third party to acquire our partnership without first negotiating such a purchase with our general partner and, as a result, our unitholders are less likely to receive a takeover premium.

***Cost reimbursements due our general partner may be substantial and will reduce the cash available for distribution to our unitholders.***

Prior to making any distributions on the units, we reimburse our general partner and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to make distributions to our unitholders. Our general partner has sole discretion to determine the amount of these expenses.

***The control of our general partner may be transferred to a third party, and that third party could replace our current management team.***

The general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the owner of the general partner from transferring its ownership interest in the general partner to a third party. The new owner of the general partner would then be in a position to replace the board of directors and officers of the general partner with its own choices and to control the decisions taken by the board of directors and officers.

***Our general partner's absolute discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.***

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to our unitholders.

***Our partnership agreement contains provisions that reduce the remedies available to our unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.***

Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to our unitholders. The partnership agreement also restricts the remedies available to our unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. If you choose to purchase a common unit, you will be treated as having consented to the various actions contemplated in the partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary duties under applicable state law.

***We may issue additional common units without our unitholders' approval, which would dilute our unitholders' ownership interests.***

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give our unitholders the right to approve our issuance of equity securities ranking junior to the common units at any time.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

***Our general partner has a limited call right that may require our unitholders to sell their common units at an undesirable time or price.***

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their units.

***Our unitholders may not have limited liability if a court finds that unitholder action constitutes control of our business.***

Our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the "control" of our business, to the extent that a person who has transacted business with the partnership reasonably believes, based on our unitholders' conduct, that our unitholders are a general

partner. Our general partner generally has unlimited liability for the obligations of the partnership, such as its debts and environmental liabilities, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of that section may be liable to the limited partnership for the amount of the distribution for a period of three years from the date of the distribution. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business.

**Tax Risks to Our Unitholders**

***Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity level taxation by individual states. If the IRS treats us as a corporation or we become subject to entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to you.***

The anticipated after-tax economic benefit of an investment in us depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us.

If we were treated as a corporation for federal income tax purposes, we would pay tax on our income at corporate rates of up to 35% (under the law as of the date of this report) and we would probably pay state income taxes as well. In addition, distributions to unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses, or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders and thus would likely result in a material reduction in the value of the common units.

A change in current law or a change in our business could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. If any of these states were to impose a tax on us, the cash available for distribution to unitholders would be reduced. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state, or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be decreased to reflect the impact of that law on us.

***A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units and the costs of any contest will be borne by us and, therefore, indirectly by our unitholders and our general partner.***

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from our counsel's conclusions expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with all of our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which our common units trade. In addition, our costs of any contest with the IRS will be borne by us and therefore indirectly by our unitholders and our general partner since such costs will reduce the amount of cash available for distribution by us.

***Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.***

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, they will be required to pay federal income taxes and, in some cases,

state, local, and foreign income taxes on their share of our taxable income even if they do not receive cash distributions from us. Unitholders may not receive cash distributions equal to their share of our taxable income or even the tax liability that results from that income. We do not currently expect to pay a distribution in the near future. See "— Restrictions in our bank credit facility may prevent us from paying distributions to our unitholders."

***Tax gain or loss on the disposition of our common units could be different than expected.***

Unitholders who sell common units will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions in excess of the total net taxable income allocated for a common unit, which decreased the tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, will likely be ordinary income to the unitholder. Should the IRS successfully contest some positions we take, unitholders could recognize more gain on the sale of units than would be the case under those positions, without the benefit of decreased income in prior years. In addition, unitholders who sell units may incur a tax liability in excess of the amount of cash they receive from the sale.

***Tax-exempt entities and foreign persons face unique tax issues from owning common units that may result in adverse tax consequences to them.***

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs) and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes, at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns and generally pay tax on their share of our taxable income. If you are a tax-exempt entity or a foreign person, you should consult your tax advisor before investing in our common units.

***We will determine the tax benefits that are available to an owner of units without regard to the units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.***

Because we cannot match transferors and transferees of common units and because of other reasons, we will take depreciation and amortization positions that may not conform to all aspects of the Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the tax returns of unitholders.

***The sale or exchange of 50% or more of our capital and profits interests within a 12-month period will result in the termination of our partnership for federal income tax purposes.***

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

***The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.***

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or

may not be applied retroactively. Specifically, federal income tax legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships and recharacterize certain types of income received from partnerships. Although the currently proposed legislation would not appear to affect our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

***As a result of investing in our common units, you will likely be subject to state and local taxes and return filing or withholding requirements in jurisdictions where you do not live.***

In addition to federal income taxes, you will likely be subject to other taxes such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property. You will likely be required to file state and local tax returns and pay state and local income taxes in some or all of the various jurisdictions in which we do business or own property and you may be subject to penalties for failure to comply with those requirements. We own property or conduct business in Texas, Oklahoma, Louisiana, New Mexico, Arkansas, Mississippi and Alabama. Oklahoma, Louisiana, New Mexico, Arkansas, Mississippi and Alabama impose an income tax, generally. Texas does not impose a state income tax on individuals, but does impose a franchise tax (to which we will be subject) on certain partnerships and other entities. We may do business or own property in other states or foreign countries in the future. It is our unitholders' responsibility to file all federal, state, local, and foreign tax returns. Under the tax laws of some states where we will conduct business, we may be required to withhold a percentage from amounts to be distributed to a unitholder who is not a resident of that state. Our counsel has not rendered an opinion on the state, local, or foreign tax consequences of owning our common units.

***We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.***

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

***A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.***

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

**Item 1B.** ***Unresolved Staff Comments***

We do not have any unresolved staff comments.

**Item 2.** ***Properties***

A description of our properties is contained in "Item 1. Business."

**Title to Properties**

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipeline was built was purchased in fee. Our processing plants are located on land that we lease or own in fee. Our treating facilities are generally located on sites provided by producers or other parties.

We believe that we have satisfactory title to all of our rights-of-way and land assets. Title to these assets may be subject to encumbrances or defects. We believe that none of such encumbrances or defects should materially detract from the value of our assets or from our interest in these assets or should materially interfere with their use in the operation of our business.

**Item 3.** ***Legal Proceedings***

Our operations are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we may be a defendant in various legal proceedings and litigation arising in the ordinary course of business, including litigation on disputes related to contracts, use or damage and personal injury. Additionally, as we continue to expand our operations into more urban, populated areas, such as the Barnett Shale, we may see an increase in claims brought by area landowners, such as nuisance claims and other claims based on property rights. Except as otherwise set forth herein, we do not believe that any pending or threatened claim or dispute is material to our financial results or our operations. We maintain insurance policies with insurers in amounts and with coverage and deductibles as our general partner believes are reasonable and prudent. However, we cannot assure that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

On November 15, 2007, Crosstex CCNG Processing Ltd. ("Crosstex Processing"), our wholly-owned subsidiary, received a demand letter from Denbury Onshore, LLC ("Denbury"), asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. The claim arises from a contract under which Crosstex Processing processed natural gas owned or controlled by Denbury in north Texas. Denbury contends that Crosstex Processing breached the processing contract (the "Processing Contract") by failing to build a processing plant of a certain size and design, resulting in Crosstex Processing's failure to properly process the gas over a ten month period. Denbury also alleges that Crosstex Processing failed to provide specific notices required under the Processing Contract. On December 4, 2007 and again on February 14, 2008, Denbury sent Crosstex Processing letters demanding that its claim be arbitrated pursuant to an arbitration provision in the Processing Contract. Denbury subsequently requested that the parties attempt to mediate the matter before any arbitration proceeding is initiated. On April 15, 2008, the parties mediated the matter unsuccessfully. On December 4, 2008, Denbury initiated formal arbitration proceedings in Dallas, Texas against Crosstex Processing, Crosstex Energy Services, L.P., Crosstex North Texas Gathering, L.P., and Crosstex Gulf Coast Marketing, Ltd., seeking $11.4 million and additional unspecified damages. On December 23, 2008, Crosstex Processing filed an answer denying Denbury's allegations and a counterclaim seeking a declaratory judgment that its processing plant is uneconomic pursuant to the terms of the Processing Contract, allowing cancellation of the contract. Crosstex Energy, Crosstex Marketing, and Crosstex Gathering also filed an answer denying Denbury's allegations and asserting that they are improper parties as Denbury's claim is for breach of the Processing Contract and none of these entities is a party to that agreement. Crosstex Gathering also filed a counterclaim seeking approximately $40.0 million in damages for the value of the NGLs it is entitled to under its Gas Gathering Agreement with Denbury. Once the three-person arbitration panel has been named and cleared conflicts, the arbitration panel will hold a preliminary conference with the parties to set a date for the final hearing and other case deadlines and to establish discovery limits. Although it is

not possible to predict with certainty the ultimate outcome of this matter, we do not believe this will have a material adverse effect on our consolidated results of operations or financial position.

During 2007 and 2008 eleven lawsuits were filed against the Partnership and its subsidiaries by owners of property located near processing facilities or compression facilities constructed by us as part of our systems in north Texas. The actions are pending in state court in Parker County and Denton County, Texas. 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. The property owners are seeking compensatory and punitive damages, attorney's fees, inverse condemnation and injunctive relief. At this time, five cases are set for trial during 2009, three of which have pending settlements, and one new case has been filed in February 2009. The remaining cases have not yet been set for trial. Discovery is underway. Although it is not possible to predict the ultimate outcomes of these matters, we do not believe that these claims will have a material adverse impact on our consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions in the U.S. Bankruptcy Court for the District of Delaware for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed us approximately $6.2 million, including approximately $3.9 million for June 2008 sales and approximately $2.2 million for July 2008 sales. We believe the July sales of $2.2 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to us for an administrative claim in the amount of approximately $2.2 million but the allowance of the administrative claim status is still subject to approval of the bankruptcy court in accordance with the administrative claim allowance procedures order in the case. We evaluated these receivables for collectability and provided a valuation allowance of $3.1 million during 2008.

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

No matters were submitted to security holders during the fourth quarter of the year ended December 31, 2008.

## PART II

**Item 5.** ***Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities***

Our common units are listed on the NASDAQ Global Select Market under the symbol "XTEX". On February 17, 2009, the closing market price for the common units was $4.05 per unit and there were approximately 11,000 record holders and beneficial owners (held in street name) of our common units and nine record holders of our 3,875,340 senior subordinated series D units. There is no established public trading market for our senior subordinated series D units.

The following table shows the high and low closing sales prices per common unit, as reported by the NASDAQ Global Select Market, for the periods indicated.

| | Common Unit Price Range(a) | | Cash Distribution Paid Per Unit(a) |
|---|---|---|---|
| | High | Low | |
| **2008:** | | | |
| Quarter Ended December 31 | $ 17.41 | $ 3.50 | $ 0.25 |
| Quarter Ended September 30 | 28.33 | 18.16 | 0.50 |
| Quarter Ended June 30 | 34.10 | 28.40 | 0.63 |
| Quarter Ended March 31 | 32.67 | 30.03 | 0.62 |
| **2007:** | | | |
| Quarter Ended December 31 | $ 34.91 | $ 31.02 | $ 0.61 |
| Quarter Ended September 30 | 38.27 | 32.78 | 0.59 |
| Quarter Ended June 30 | 36.45 | 33.56 | 0.57 |
| Quarter Ended March 31 | 39.56 | 33.49 | 0.56 |

(a) For each quarter, an identical cash distribution was paid on all outstanding subordinated units (excluding senior subordinated units).

Unless restricted by the terms of our credit facility, within 45 days after the end of each quarter, we will distribute all of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. Our available cash consists generally of all cash on hand at the end of the fiscal quarter, less reserves that our general partner determines are necessary to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;
- plus all cash on hand for the quarter resulting from working capital borrowings made after the end of the quarter on the date of determination of available cash.

Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Our distributions are effectively made 98.0% to unitholders and two percent to our general partner, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Incentive distributions to our general partner increase to 13.0%, 23.0% and 48.0% based on incremental distribution thresholds as set forth in our partnership agreement.

Our ability to distribute available cash is contractually restricted by the terms of our credit facility. Our credit facility contains covenants requiring us to maintain certain financial ratios. If our leverage ratio, as defined in the credit facility, falls below a certain level we will be prohibited from making distributions or from making more than the minimum quarterly distributions. Based on our forecasted leverage ratios for 2009, we do not anticipate making quarterly distributions during 2009 other than the distribution paid in February 2009 related to fourth quarter 2008 operating results. See Item 1, “Business — Amendments to Credit Documents.” Additionally, we are prohibited from making any distributions to unitholders if the distribution would cause an event of default, or an event of default is existing, under our credit facility. Please read Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Description of Indebtedness.”

**Conversion of Senior Subordinated Series D Units**

The 3,875,340 senior subordinated series D units are scheduled to convert into common units on March 23, 2009. Since the distribution for the quarter ended December 31, 2008 was less than $0.62 per unit, the senior subordinated units will convert into common units at a ratio of 1.05 common units for each senior subordinated series D unit.

**Equity Compensation Plan Information**

| Plan Category | Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a) | Weighted-Average Price of Outstanding Options, Warrants and Rights (b) | Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column(a)) (c) |
|---|---|---|---|
| Equity Compensation Plans Approved By Security Holders | N/A | N/A | N/A |
| Equity Compensation Plans Not Approved By Security Holders | 2,002,760(1)(2) | $ 30.64(3) | 1,915,696 |

(1) Our general partner has adopted and maintains a long term incentive plan for our officers, employees and directors. See Item 11, "Executive Compensation — Compensation Discussion and Analysis." The plan, as amended, provides for issuance of a total of 4,800,000 common unit options and restricted units.

(2) The number of securities includes (i) 477,858 restricted units that have been granted under our long-term incentive plan that have not vested, and (ii) 220,708 performance units which could result in grants of restricted units in the future.

(3) The exercise prices for outstanding options under the plan as of December 31, 2008 range from $10.00 to $37.31 per unit.

**Item 6.** ***Selected Financial Data***

The following table sets forth selected historical financial and operating data of Crosstex Energy, L.P. as of and for the dates and periods indicated. The selected historical financial data are derived from the audited financial statements of Crosstex Energy, L.P. In addition, our summary historical financial and operating data include the results of operations of the LIG assets beginning in April 2004, the Graco assets beginning January 2005, the Cardinal assets beginning May 2005, the south Louisiana processing assets beginning November 2005, the Hanover assets beginning January 2006, the NTP beginning April 2006 and the Chief midstream assets beginning June 2006 and other smaller acquisitions completed in 2006.

The table should be read together with "Management's Discussion and Analysis of Financial Condition and Results of Operations."

| | Crosstex Energy, L.P. Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2008 | 2007 | 2006 | 2005 | 2004 |
| | (In thousands, except per unit data) | | | | |
| **Statement of Operations Data:** | | | | | |
| Revenues: | | | | | |
| Midstream | $ 4,838,747 | $ 3,791,316 | $ 3,075,481 | $ 2,982,874 | $ 1,948,021 |
| Treating | 64,953 | 53,682 | 52,095 | 38,838 | 24,871 |
| Profit on energy trading activities | 3,349 | 4,090 | 2,510 | 1,568 | 2,228 |
| Total revenues | 4,907,049 | 3,849,088 | 3,130,086 | 3,023,280 | 1,975,120 |
| Operating costs and expenses: | | | | | |
| Midstream purchased gas | 4,471,308 | 3,468,924 | 2,859,815 | 2,860,823 | 1,861,204 |
| Treating purchased gas | 14,579 | 7,892 | 9,463 | 9,706 | 5,274 |

| | Crosstex Energy, L.P. | | | | |
|---|---|---|---|---|---|
| | Years Ended December 31, | | | | |
| | 2008 | 2007 | 2006 | 2005 | 2004 |
| | (In thousands, except per unit data) | | | | |
| Operating expenses | 169,048 | 125,149 | 98,794 | 54,658 | 38,340 |
| General and administrative | 71,005 | 61,528 | 45,694 | 32,697 | 20,866 |
| (Gain) loss on derivatives | (12,203) | (6,628) | (1,591) | 9,966 | (414) |
| Gain on sale of property | (1,519) | (1,667) | (2,108) | (8,138) | (12) |
| Impairments | 30,436 | — | — | — | — |
| Depreciation and amortization | 131,187 | 106,639 | 80,518 | 33,841 | 20,855 |
| Total operating costs and expenses | 4,873,841 | 3,761,837 | 3,090,585 | 2,993,553 | 1, 946,113 |
| Operating income | 33,208 | 87,251 | 39,501 | 29,727 | 29,007 |
| Other income (expense): | | | | | |
| Interest expense, net | (102,675) | (79,403) | (51,427) | (15,767) | (9,220) |
| Other income | 27,757 | 683 | 183 | 392 | 798 |
| Total other income (expense) | (74,918) | (78,720) | (51,244) | (15,375) | (8,422) |
| Income (loss) from continuing operations before minority interest, income taxes and cumulative effect change in accounting principle | (41,710) | 8,531 | (11,743) | 14,352 | 20,585 |
| Minority interest subsidiary | (311) | (160) | (231) | (441) | (289) |
| Income tax provision | (2,765) | (964) | (222) | (216) | (162) |
| Income (loss) from continuing operations before discontinued operations and cumulative effect of change in accounting principle | (44,786) | 7,407 | (12,196) | 13,695 | 20,134 |
| Discontinued Operations: | | | | | |
| Income from discontinued operations | 5,752 | 6,482 | 7,316 | 5,505 | 3,570 |
| Gain on sale of discontinued operations | 49,805 | — | — | — | — |
| Discontinued operations | 55,557 | 6,482 | 7,316 | 5,505 | 3,570 |
| Net income (loss) before cumulative effect of change in accounting principle | 10,771 | 13,889 | (4,880) | 19,200 | 23,704 |
| Cumulative effect of change in accounting principle | — | — | 689 | — | — |
| Net income (loss) | $ 10,771 | $ 13,889 | $ (4,191) | $ 19,200 | $ 23,704 |
| Net income (loss) per limited partner unit — basic | $ (3.23) | $ (0.20) | $ (1.09) | $ 0.56 | $ 0.98 |
| Net income (loss) per limited partner unit — diluted | $ (3.23) | $ (0.20) | $ (1.09) | $ 0.51 | $ 0.95 |
| Net income (loss) per limited partner senior subordinated unit A— basic and diluted | — | — | $ 5.31 | — | — |
| Net income per limited partner senior subordinated unit series C — basic and diluted | $ 9.44 | — | — | — | — |
| Distributions per limited partner unit(1) | $ 2.00 | $ 2.33 | $ 2.18 | $ 1.93 | $ 1.70 |
| **Balance Sheet Data (end of period):** | | | | | |
| Working capital deficit | $ (32,910) | $ (46,888) | $ (79,936) | $ (11,681) | $ (34,724) |
| Property and equipment, net | 1,527,280 | 1,425,162 | 1, 105,813 | 667,142 | 324,730 |
| Total assets | 2,533,266 | 2,592,874 | 2,194,474 | 1,425,158 | 586,771 |
| Long-term debt | 1,263,706 | 1,223,118 | 987,130 | 522,650 | 148,700 |
| Partners' equity | 794,421 | 784,826 | 711,877 | 401,285 | 144,050 |
| **Cash Flow Data:** | | | | | |
| Net cash flow provided by (used in): | | | | | |
| Operating activities | $ 173,750 | $ 114,818 | $ 113,010 | $ 14,010 | $ 48,103 |
| Investing activities | (186,810) | (411,382) | (885,825) | (615,017) | (124,371) |
| Financing activities | 14,554 | 295,882 | 772,234 | 596,615 | 81,899 |
| **Other Financial Data:** | | | | | |
| Midstream gross margin | $ 370,788 | $ 326,482 | $ 218,176 | $ 123,619 | $ 89,045 |
| Treating gross margin | 50,374 | 45,790 | 42,632 | 29,132 | 19,597 |
| Total gross margin(2) | $ 421,162 | $ 372,272 | $ 260,808 | $ 152,751 | $ 108,642 |

| | Crosstex Energy, L.P. | | | | |
|---|---|---|---|---|---|
| | Years Ended December 31, | | | | |
| | 2008 | 2007 | 2006 | 2005 | 2004 |
| | (In thousands, except per unit data) | | | | |
| **Operating Data:** | | | | | |
| Pipeline throughput (MMBtu/d) | 2,608,000 | 2,114,000 | 1,356,000 | 1,126,000 | 1,289,000 |
| Natural gas processed (MMBtu/d)(3) | 1,812,000 | 2,057,000 | 2,032,000 | 1,921,000 | 425,000 |
| Producer Services (MMBtu/d) | 85,000 | 94,000 | 138,000 | 175,000 | 210,000 |

(1) Distributions include fourth quarter 2008 distributions of $0.25 per unit paid in February 2009; fourth quarter 2007 distributions of $0.61 per unit paid in February 2008; fourth quarter 2006 distributions of $0.56 per unit paid in February 2007; fourth quarter 2005 distributions of $0.51 per unit paid in February 2006; fourth quarter 2004 distributions of $0.45 per unit paid in February 2005; and fourth quarter 2003 distributions of $0.375 per unit paid in February 2004.

(2) Gross margin is defined as revenue, including treating fee revenues and profit on energy trading activities, less related cost of purchased gas.

(3) For the year ended 2005, processed volumes include a daily average for the south Louisiana processing plants for November 2005 and December 2005, the two-month period these assets were operated by us.

## Item 7. *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. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the financial statements included in this report.*

### Overview

We are a Delaware limited partnership formed on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, while our Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the year ended December 31, 2008, approximately 88.0% of our gross margin was generated in the Midstream division with the balance in the Treating division. We manage our operations by focusing on gross margin because our business is generally to purchase and resell natural gas for a margin, or to gather, process, transport, market or treat natural gas or NGLs for a fee. We buy and sell most of our natural gas at a fixed relationship to the relevant index price. In addition, we receive certain fees for processing based on a percentage of the liquids produced and enters into hedge contracts for our expected share of the liquids produced to protect our margins from changes in liquids prices.

During the past five years we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2004 through December 31, 2008, we have invested over $2.3 billion to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, and the volumes of NGLs

handled at our fractionation facilities. Our Treating segment margins are largely a function of the number and size of treating plants in operation. We generate Midstream revenues from six primary sources:

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

With respect to our Midstream 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. In our purchase/sale transactions, the resale price is generally based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas.

We also realize margins in our Midstream segment from our processing services primarily through three different contract arrangements: processing margins (margin), percentage of liquids (POL) or fee based. Under the margin and POL contract arrangements our margins are higher during periods of high liquid prices relative to natural gas prices. Under fee based contracts our margins are driven by throughput volume. See "—Commodity Price Risk."

We generate Treating revenues under three types of arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 11.0% of operating income in our Treating division for the years ended December 31, 2008 and 2007;
- a fixed fee for operating a plant for a certain period, which accounted for approximately 62.0% and 59.0% of operating income in our Treating division for the years ended December 31, 2008 and 2007, respectively; and
- a fee arrangement in which the producer operates the plant, which accounted for approximately 27.0% and 30.0% of operating income in our Treating division for the years ended December 31, 2008 and 2007, respectively.

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

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

**Recent Developments**

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. Numerous events during 2008 have severely restricted current liquidity in the capital markets throughout the United States and around the world. The ability to raise money in the debt and equity markets has diminished significantly and, if available, the cost of funds has increased substantially. One of the features driving investments

in MLPs , including the Partnership, over the past few years has been the distribution growth offered by MLPs due to liquidity in the financial markets for capital investments to grow distributable cash flow through development projects and acquisitions. Future growth opportunities have been and are expected to continue to be constrained by the lack of liquidity in the financial markets.

In addition, our business has been significantly impacted by the substantial decline in crude oil prices during the last half of 2008 from a high of approximately $145 per Bbl in July 2008 to a low of approximately $34 per Bbl in December 2008 (based on NYMEX futures daily close prices for the prompt month), a 76.7% decline, and the related 78.2% decline in NGL prices from a high of $2.19 per gallon in July 2008 to a low of $0.48 per gallon in December 2008 (based on the OPIS Mt. Belvieu daily average spot liquids prices). Crude oil prices reflected on NYMEX during January and February 2009 have fluctuated, to a lesser extent, between $49 per Bbl and $35 per Bbl while the OPIS Mt. Belvieu NGL prices have improved slightly ranging from $0.81 per gallon and $0.62 per gallon. The declines in NGL prices have negatively impacted our gross margin for the fourth quarter of 2008 and could continue to negatively impact our gross margin (revenue less cost of gas purchases) in 2009. A significant percentage of inlet gas at our processing plants is settled under percent of liquids (POL) agreements or fractionation margin (margin) contracts. Over the past two years the inlet processing volumes associated with POL and margin contracts were approximately 70%, on a combined basis, of the total volume of gas processed. The POL fees are denominated in the form of a share of the liquids extracted. Therefore, fee revenue under a POL agreement is directly impacted by NGL prices and the decline of these prices in 2008 contributed to a significant decline in gross margin from processing. Under the POL settlement terms, we are not responsible for the fuel or shrink associated with processing. Under margin contracts we realize a gross margin from processing based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state and the cost of fuel to extract. This is often referred to as the fractionation spread. During the last half of 2008 the “fractionation spread” narrowed significantly as the value of NGLs decreased more than the value of the gas and fuel associated with the processed gas. Thus the gross margin realized under these margin contracts was also negatively impacted due to the commodity price environment. If the current weakness in the economy continues for a prolonged period, it would likely further reduce demand for gas and for NGL products, such as ethane, a primary feedstock for the petrochemical and manufacturing industries, and result in continued lower natural gas and NGL prices. Although we have seen some improvement in NGL prices and the fractionation spread in the early months of 2009 over the levels experienced in December 2008, we believe that our processing margins in 2009 will be substantially lower than the processing margins realized in 2008 based on current market indicators. For the year ended December 31, 2008, approximately 38.7% of our gross margin was attributable to gas processing as compared to 46.1% of our gross margin for the year ended December 31, 2007. See Item 7A, “Quantitative and Qualitative Disclosures about Market Risk-Commodity Price Risk” for a description of our contractual processing arrangements.

Natural gas prices have declined by approximately 61.0%, from a high of $13.58 per MMBtu in July 2008 to a low of $5.29 per MMBtu in December 2008 (based on NYMEX futures daily close prices for the prompt month). Natural gas prices have declined even further during January and February 2009 with prices ranging from $6.07 in early January to $4.01 in mid-February. Many of our customers finance their drilling activity with cash flow from operations, which have been negatively impacted by the declines in natural gas and crude oil prices, or through the incurrence of debt or issuance of equity, which markets have been adversely impacted by global financial market conditions. We believe that the adverse price changes coupled with the overall downturn in the economy and the constrained capital markets will put downward pressure on drilling budgets for gas producers which could result in lower volumes being transported on our pipeline and gathering systems and processing through our processing plants. We have seen a decline in drilling activity by gas producers in our areas of operations during the fourth quarter of 2008. In addition, industry drilling rig count surveys published in early 2009 show substantial declines in rigs in operation as compared to 2008. Several of our customers, including one of our largest customers in the Barnett Shale, have recently announced drilling plans for 2009 that are substantially below their drilling levels during 2008.

Our business was also negatively impacted by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September 2008. Although the majority of our assets in Texas and Louisiana sustained minimal physical damage from these hurricanes and promptly resumed operations, several offshore production platforms and pipelines that transport gas production to our Pelican, Eunice, Sabine Pass and Blue Water processing plants in south Louisiana

were damaged by the storms. Some of the repairs to these offshore facilities were completed during the fourth quarter of 2008 but we do not anticipate that gas production to our south Louisiana plants will recover to pre-hurricane levels until mid-2009, when all repairs are expected to be complete. Additionally, one of our south Louisiana processing plants, the Sabine Pass processing plant, which is located on the shoreline of the Louisiana Gulf Coast, sustained some physical damage. The Sabine Pass processing plant was repaired during the fourth quarter of 2008 and the plant was returned to service in early January 2009. Our operations in north Texas were also impacted by these hurricanes because operations at the Mt. Belvieu, Texas, a central distribution point for NGL sales where several fractionators are located which fractionate NGLs from the entire United States, were interrupted as a result of these storms. These storms resulted in an adverse impact to our gross margin of approximately $22.9 million.

Two of our facilities, one in south Louisiana and one in north Texas, were also partially damaged by fires during 2008. Although substantially all of the property repairs were covered by insurance, our Sabine Pass processing plant in south Louisiana was out of service for approximately one month. The loss of operating income due to the fire at the Godley compressor station in north Texas was minimal because we were successful in rerouting the gas to our other facilities in the area until the damaged compressor was replaced. The estimated loss in gross margin as a result of these fires is $0.9 million.

**Acquisitions and Expansion**

We have grown significantly through asset purchases and construction and expansion projects in recent years. This growth creates many of the major differences when comparing operating results from one period to another. The most significant asset purchases since January 2006 were the acquisition of midstream assets from Chief Holdings, LLC, or Chief in June 2006, the Hanover Compression Company treating assets in February 2006 and the amine-treating business of Cardinal Gas Solutions L.P. in October 2006. In addition, internal expansion projects in north Texas and Louisiana have contributed to the increase in our business during 2006, 2007 and 2008.

On June 29, 2006, we expanded our operations in the north Texas area through our acquisition of the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems included gathering pipeline, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that acquisition, approximately 160,000 net acres previously owned by Chief and acquired by Devon, simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. The continued expansion of our north Texas gathering systems to handle the growing production in the Barnett Shale was one of our core areas for internal growth during 2006, 2007 and 2008 and will continue to be a core area during 2009. Since the date of the acquisition through December 31, 2008, we connected 444 new wells to our gathering system and significantly increased the dedicated acreage owned by other producers. Our processing capacity in the Barnett Shale is 280 MMcf/d including the Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, our Azle plant, which is a 50 MMcf/d cryogenic processing plant, and our Goforth plant, which is a 30 MMcf/d processing plant. In 2007 and 2008, we constructed a 29-mile expansion in north Johnson County to our north Texas gathering systems. The first phase of the expansion commenced operation in September 2007. The last two phases of the expansion commenced operation in May and July of 2008. The total gathering capacity of this 29-mile expansion is currently 235 MMcf/d and is expected to be increased to approximately 400 MMcf/d in April 2009 by the addition of compression. We have also installed two 40 gallon per minute and one 100 gallon per minute amine treating plants to provide carbon dioxide removal capability. As of December 2008, the capacity of our north Texas gathering system was approximately 1,100 MMcf/d and total throughput on our north Texas gathering systems, including the north Johnson County expansion, had increased from approximately 115,000 MMBtu/d at the time of the Chief acquisition to approximately 796,000 MMBtu/d.

In April 2008, we commenced construction of an $80.0 million natural gas processing facility called Bear Creek in Hood County near our existing North Texas Assets. The new plant will have a gas processing capacity of 200 MMcf/d. Due to the recent decline in commodity prices and the corresponding decline in drilling activity, we do not anticipate that the additional processing capacity provided by the Bear Creek plant will be needed until late 2010 or in 2011. Therefore, we have decided to put this construction project on hold until the demand for this processing capacity returns, at which time we will seek to obtain financing for this project. As of December 31, 2008, we have

spent approximately $20.2 million on this project for the construction of a portion of the plant that will be utilized when the plant is completed in the future.

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

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

Our NTP, which commenced service in April 2006, consists of a 133-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas. The initial capacity of the NTP was approximately 250 MMcf/d. In 2007, we expanded the capacity on the NTP to a total of approximately 375 MMcf/d. The NTP connects production from the Barnett Shale to markets in north Texas and to markets accessed by NGPL, Kinder Morgan, HPL, Atmos and other markets. As of December 2008, the total throughput on the NTP was approximately 300,000 MMBtu/d. The NTP also will interconnect with a new interstate gas pipeline under construction by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing Pipeline which is expected to be in service in March 2009. The Gulf Crossing Pipeline is expected to provide our customer's access to premium midwest and east coast markets.

In April 2007, we completed construction and commenced operations on our north Louisiana expansion, which is an extension of our LIG system designed to increase take-away pipeline capacity to the producers developing natural gas in the fields south of Shreveport, Louisiana. The north Louisiana expansion consists of approximately 63 miles of 24" mainline with 9 miles of 16" gathering lateral pipeline and 10,000 horsepower of new compression referred to as our Red River lateral. Our Red River lateral bisects the developing Haynesville Shale gas play in north Louisiana. The Red River lateral was operating at near capacity during 2008 so we added 35 MMcf/d of capacity by adding compression during the third quarter of 2008 bringing the total capacity of the Red River lateral to approximately 275 MMcf/d. As of December 31, 2008, the Red River lateral was flowing at approximately 225,000 MMBtu/d. Interconnects on the north Louisiana expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission and Trunkline Gas.

**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. A large percentage of our processing fees are realized under POL contracts that are directly impacted by the market price of NGLs. We also realize processing gross margins under margin contracts. These settlements are impacted by the relationship between NGL prices and the underlying natural gas prices, which is also referred to as the fractionation spread.

A significant volume of inlet gas at our south Louisiana and north Texas processing plants is settled under POL agreements. The POL fees are denominated in the form of a share of the liquids extracted and we are not responsible for the fuel or shrink associated with processing. Therefore, fee revenue under a POL agreement is directly impacted by NGL prices, and the decline of these prices in 2008 contributed to a significant decline in gross margin from processing. We have a number of fractionation margin contracts on our Plaquemine and Gibson processing plants that expose us to the fractionation spread. Under these margin contracts our gross margin is based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state and the cost of fuel to extract during processing. During the last half of 2008 the fractionation spread narrowed significantly as the value of NGLs decreased more than the value of the gas and fuel associated with the processed gas. Thus the gross margin realized under these margin contracts was negatively impacted due to the commodity price environment. The significant decline in crude oil prices and a related decline in NGL prices during the last half of 2008 had a significant negative impact on our margins, and may negatively impact our gross margin further if such declines continue.

We are also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transportation services. Approximately 4.0% of the natural gas we market is purchased at a

percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices.

See Item 7A, "Quantitative and Qualitative Disclosures about Market Risk-Commodity Price Risk" for additional information on Commodity Price Risk.

**Results of Operations**

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Dollars in millions) | |
| Midstream revenues | $ 4,838.7 | $ 3,791.3 | $ 3,075.5 |
| Midstream purchased gas | (4,471.3) | (3,468.9) | (2,859.8) |
| Profits on energy trading activities | 3.4 | 4.1 | 2.5 |
| Midstream gross margin | 370.8 | 326.5 | 218.2 |
| Treating revenues | 65.0 | 53.7 | 52.1 |
| Treating purchased gas | (14.6) | (7.9) | (9.5) |
| Treating gross margin | 50.4 | 45.8 | 42.6 |
| Total gross margin | $ 421.2 | $ 372.3 | $ 260.8 |
| **Midstream Volumes (MMBtu/d):** | | | |
| Gathering and transportation | 2,608,000 | 2,114,000 | 1,356,000 |
| Processing | 1,812,000 | 2,057,000 | 2,032,000 |
| Producer services | 85,000 | 94,000 | 138,000 |
| **Treating Plants in Operation at Year-end** | 200 | 190 | 190 |

***Year Ended December 31, 2008 Compared to Year Ended December 31, 2007***

*Gross Margin and Profit on Energy Trading Activities.* Midstream gross margin was $370.8 million for the year ended December 31, 2008 compared to $326.5 million for the year ended December 31, 2007, an increase of $44.3 million, or 13.6%. The increase was primarily due to system expansion projects and increased throughput on our gathering and transmission systems. These increases were partially offset by margin decreases in the processing business due to a less favorable NGL market and operating downtime resulting from the impact of hurricanes in the last half of the year. Profit on energy trading activities decreased for the comparative periods by approximately $0.7 million.

System expansion in the north Texas region and increased throughput on the NTP contributed $58.9 million of gross margin growth for the year ended December 31, 2008 over the same period in 2007. Our gathering systems in the region and NTP accounted for $41.3 million and $9.1 million of this increase, respectively. Our processing facilities in the region contributed an additional $8.5 million of gross margin increase. System expansion and volume increases on the LIG system contributed margin growth of $8.2 million during the year ended December 31, 2008 over the same period in 2007. Processing plants in Louisiana experienced a margin decline of $20.2 million for the comparative twelve-month period in 2008 due to a less favorable NGL processing environment in the last half of the year and business interruptions resulting from the impact of hurricanes along the Gulf Coast. These unfavorable processing conditions also contributed to margin declines in south Texas on the Vanderbilt system and Gregory Processing facility of $2.9 million and $1.8 million, respectively. A throughput decline on the Gregory Gathering system resulted in a gross margin decrease of $1.6 million. These declines were partially offset by a gross margin increase on the CCNG system of $1.9 million due to an increase in throughput. The Mississippi system had a margin

increase of $1.2 million due to increased throughput, and an expansion of the east Texas system contributed to a margin increase of $0.9 million for the comparable periods.

Our processing and gathering systems were negatively impacted by events beyond our control during the third quarter that had a significant effect on gross margin results for the year ended December 31, 2008. Hurricanes Gustav and Ike came ashore along the Gulf Coast in September 2008. We estimate that these storms resulted in an approximately $22.9 million gross margin decrease for the year. The lost margin was primarily experienced at gas processing facilities along the Gulf Coast. However, processing facilities further inland in Louisiana and north Texas were indirectly impacted due to disruption in the NGL markets. In addition, approximately $0.9 million in gross margin was lost at the Sabine Pass plant in August 2008 due to downtime from fire damage. The fire occurred during an attempt to bring the plant back online following tropical storm Edouard.

Treating gross margin was $50.4 million for the year ended December 31, 2008 compared to $45.8 million for the year ended December 31, 2007, an increase of $4.6 million, or 10.0%. We had approximately 200 and 190 treating plants, dew point control plants, and related equipment in service at December 31, 2008 and 2007, respectively. Gross margin growth for the period of $3.2 million is attributable primarily to the increase in the number of plants and an increase in throughput on the volume based plants. Field services provided to producers also contributed gross margin growth of $1.4 million for the comparable periods.

*Operating Expenses.* Operating expenses were $169.0 million for the year ended December 31, 2008 compared to $125.1 million for the year ended December 31, 2007, an increase of $43.9 million, or 35.1%. The increase is primarily attributable to the following factors:

- $35.8 million increase in Midstream operating expenses resulting primarily from growth and expansion in the NTP, NTG, north Louisiana and east Texas areas. Contractor services and labor costs increased $14.1 million, chemicals and materials increased $7.8 million, equipment rental increased $7.4 million and ad valorem taxes increased $2.4 million;
- $7.3 million increase in Treating operating expenses, including $2.6 million for materials and supplies, contractor services costs of $2.8 million to support maintenance projects, labor costs of $1.4 million as a result of market adjustments for field service employees and additional headcount and auto-related expenses of $0.5 million; and
- $0.7 million increase in technical services operating expense.

*General and Administrative Expenses.* General and administrative expenses were $71.0 million for the year ended December 31, 2008 compared to $61.5 million for the year ended December 31, 2007, an increase of $9.5 million, or 15.4%. The increase is primarily attributable to the following factors:

- $5.5 million increase in rental expense resulting primarily from additional office rent and including $3.4 million related to lease termination fees for the cancelled relocation of our corporate headquarters;
- $3.1 million increase in bad debt expense due to the SemStream, L.P. bankruptcy;
- $1.8 million increase in other expenses, including professional fees and services and labor and benefit expenses; and
- $0.9 million decrease in stock-based compensation expense resulting primarily from the reduction of estimated performance-based restricted units and restricted shares.

*Gain/Loss on Derivatives.* We had a gain on derivatives of $12.2 million for the year ended December 31, 2008 compared to a gain of $6.6 million for the year ended December 31, 2007. The derivative transaction types contributing to the net gain are as follows (in millions):

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2008 | | 2007 | |
| (Gain)/Loss on Derivatives: | Total | Realized | Total | Realized |
| Basis swaps | $ (7.2) | $ (7.3) | $ (8.1) | $ (7.0) |
| Processing margin hedges | (3.6) | (3.6) | 1.3 | 1.3 |
| Storage | (0.7) | (0.1) | (0.5) | (1.6) |
| Third-party on-system swaps | (0.6) | (0.8) | (0.2) | (0.6) |
| Puts | — | — | 0.8 | — |
| Other | (0.1) | — | 0.1 | — |
| | $ (12.2) | $ (11.8) | $ (6.6) | $ (7.9) |

*Gain/Loss on Sale of Property.* Assets sold during the year ended December 31, 2008 generated a net gain of $1.5 million as compared to a gain of $1.7 million during the year ended December 31, 2007. The 2008 gain was primarily generated from the disposition of various small Treating and Midstream assets. The 2007 gain was primarily generated from the disposition of unused catalyst material and the disposition of a treating plant.

*Impairments.* During the year ended December 31, 2008, we had an impairment expense of $30.4 million compared to no impairment expense for the year ended December 31, 2007. The impairment expense is comprised of:

- $17.8 million related to the Blue Water gas processing plant located in south Louisiana — The impairment on our 59.27% interest in the Blue Water gas processing plant was recognized because the pipeline company which owns the offshore Blue Water system and supplies gas to our Blue Water plant reversed the flow of the gas on its pipeline in early January 2009 thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system. At this time, we have not found an alternative source of new gas for the Blue Water plant so the plant ceased operation in January 2009. An impairment of $17.8 million was recognized for the carrying amount of the plant in excess of the estimated fair value of the plant as of December 31, 2008.
- $4.9 million related to goodwill — We determined that the carrying amount of goodwill attributable to the Midstream segment was impaired because of the significant decline in our Midstream operations due to negative impacts on cash flows caused by the significant declines in natural gas and NGL prices during the last half of 2008 coupled with the global economic decline.
- $4.1 million related to leasehold improvements — We had planned to relocate our corporate headquarters during 2008 to a larger office facility. We had leased office space and were close to completing the renovation of this office space when the global economic decline began impacting our operations in October 2008. On December 31, 2008, the decision was made to cancel the new office lease and not relocate the corporate offices from its existing office location. The impairment relates to the leasehold improvements on the office space for the cancelled lease.
- $2.6 million related to the Arkoma gathering system — The impairment on the Arkoma gathering system was recognized because we sold this asset in February 2009 for $11.0 million and the carrying amount of the plant exceeded the sale price by approximately $2.6 million.
- $1.0 million related to unused treating equipment — The impairment relates to older equipment in the Treating division that will not be used in our future operations.

*Depreciation and Amortization.* Depreciation and amortization expenses were $131.2 million for the year ended December 31, 2008 compared to $106.6 million for the year ended December 31, 2007, an increase of $24.5 million, or 23.0%. Midstream depreciation and amortization increased $23.0 million due to the NTP, NTG

and north Louisiana expansion project assets. Accelerated depreciation of the Dallas office leasehold due to the planned, but subsequently cancelled, relocation accounted for an increase between periods of $1.4 million.

*Interest Expense.* Interest expense was $102.7 million for the year ended December 31, 2008 compared to $79.4 million for the year ended December 31, 2007, an increase of $23.3 million, or 29.3%. The increase relates primarily to the negative impact of declining interest rates on our interest rate swaps. Net interest expense consists of the following (in millions):

| | Years Ended December 31, | |
|---|---|---|
| | 2008 | 2007 |
| Senior notes | $ 33.1 | $ 33.4 |
| Credit facility | 39.4 | 47.2 |
| Capitalized interest | (2.7) | (4.8) |
| Mark to market interest rate swaps | 22.1 | 1.1 |
| Realized interest rate swaps | 4.6 | (0.7) |
| Interest income | (0.3) | (0.7) |
| Other | 6.5 | 3.9 |
| Total | $ 102.7 | $ 79.4 |

*Income taxes.* Income tax expense was $2.8 million for the year ended December 31, 2008 compared to $1.0 million for the year ended December 31, 2007, an increase of $1.8 million. The increase relates primarily to the Texas margin tax.

*Other Income.* Other income was $27.8 million for the year ended December 31, 2008 compared to $0.7 million for the year ended December 31, 2007. In November 2008, the Partnership sold a contract right for firm transportation capacity on a third party pipeline to an unaffiliated third party for $20.0 million. The entire amount of such proceeds is reflected in other income because the Partnership had no basis in this contract right. In February 2008, the Partnership recorded $7.0 million from the settlement of disputed liabilities that were assumed with an acquisition.

*Discontinued Operations.* Discontinued operations were $55.6 million for the year ended December 31, 2008 compared to $6.5 million for the year ended December 31, 2007. In November 2008, we sold our undivided 12.4% interest in the Seminole gas processing plant to an unrelated third party and realized a gain on the sale of $49.8 million.

***Year Ended December 31, 2007 Compared to Year Ended December 31, 2006***

*Gross Margin and Profit on Energy Trading Activities.* Midstream gross margin was $326.5 million for the year ended December 31, 2007 compared to $218.2 million for the year ended December 31, 2006, an increase of $108.3 million, or 49.6%. This increase was primarily due to system expansions, increased system throughput and a favorable processing environment for natural gas and NGLs.

Crosstex acquired the NTG assets from Chief in June 2006. System expansion in the north Texas region and increased throughput on the NTP contributed $64.5 million of gross margin growth during the year ended December 31, 2007 over the same period in 2006. The NTG and NTP assets accounted for $34.1 million and $16.6 million of this increase, respectively. The processing facilities in the region contributed an additional $13.3 million of this gross margin increase. Operational improvements, system expansion and increased volume on the LIG system coupled with optimization and integration with the south Louisiana processing assets contributed margin growth of $22.6 million for 2007. Volume increases on the Mississippi system contributed gross margin growth of $5.7 million. The Plaquemine and Gibson plants contributed margin growth of $9.9 million due to a favorable gas processing environment. The favorable gas processing margin also led to a combined $5.3 million margin increase on the Vanderbilt and Gulf Coast systems.

The favorable processing margins we realized during 2007 at several of our processing facilities may be higher than margins we currently are realizing or may realize in future periods due to the current economic environment and NGL prices. As discussed above under "— *Commodity Price Risk*", we receive as a processing fee a percentage of the liquids recovered on a substantial portion of the gas processed through our plants. Also, during periods when processing margins are favorable due to liquids prices being high relative to natural gas prices, as existed during 2007, we have the ability to generate higher processing margins. We have the ability to bypass certain volumes when processing is uneconomical so we can avoid negative processing margins but our margins will be lower during these periods.

In addition, we have the ability to buy gas from and to sell gas to various gas markets through our pipeline systems. During 2007 we were able to benefit from price differentials between the various gas markets by selling gas into markets with more favorable pricing thereby improving our Midstream gross margin.

Treating gross margin was $45.8 million for the year ended December 31, 2007 compared to $42.6 million for the year ended December 31, 2006, an increase of $3.2 million, or 7.4%. There were approximately 190 treating and dew point control plants in service at December 31, 2007. Although the number of plants in service was unchanged from December 31, 2006, gross margin growth for 2007 is attributed to a higher average number of plants in service each month during 2007 compared to 2006.

*Operating Expenses.* Operating expenses were $125.1 million for the year ended December 31, 2007 compared to $98.8 million for the year ended December 31, 2006, an increase of $26.4 million, or 26.7%. The increase in operating expenses primarily reflects costs associated with growth and expansion in the north Texas assets of $17.5 million, the south Texas assets of $1.8 million, LIG and the north Louisiana expansion of $3.7 million and Treating assets of $1.6 million. Operating expenses included $1.8 million of stock-based compensation expense in 2007 compared to $1.1 million of stock-based compensation expense in 2006.

*General and Administrative Expenses.* General and administrative expenses were $61.5 million for the year ended December 31, 2007 compared to $45.7 million for the year ended December 31, 2006, an increase of $15.8 million, or 34.7%. Additions to headcount associated with the requirements of NTP and NTG assets and the expansion in north Louisiana accounted for $8.9 million of the increase. Consulting for system and process improvements resulted in $2.8 million of the increase. General and administrative expenses included stock-based compensation expense of $10.2 million and $7.4 million in 2007 and 2006, respectively.

*Gain/Loss on Derivatives.* We had a gain on derivatives of $6.6 million for the year ended December 31, 2007 compared to a gain of $1.6 million for the year ended December 31, 2006. The derivative transaction types contributing to the net gain are as follows (in millions):

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2007 | | 2006 | |
| (Gain) Loss on Derivatives: | Total | Realized | Total | Realized |
| Basis swaps | $ (8.1) | $ (7.0) | $ (0.7) | $ (0.4) |
| Processing margin hedges | 1.3 | 1.3 | — | — |
| Storage | (0.5) | (1.6) | (2.9) | (0.7) |
| Third-party on-system swaps | (0.2) | (0.6) | (1.5) | (1.2) |
| Puts | 0.8 | — | 3.6 | — |
| Other | 0.1 | — | (0.1) | — |
| | $ (6.6) | $ (7.9) | $ (1.6) | $ (2.3) |

*Gain/Loss on Sale of Property.* Assets sold during the year ended December 31, 2007 generated a net gain of $1.7 million as compared to a gain of $2.1 million during the year ended December 31, 2006. The 2007 gain was primarily generated from the disposition of unused catalyst material and the disposition of a treating plant. The gain in 2006 primarily related to the sale of inactive gas processing facilities acquired as a part of the south Louisiana processing assets and as part of LIG acquisition.

*Depreciation and Amortization.* Depreciation and amortization expenses were $106.6 million for the year ended December 31, 2007 compared to $80.5 million for the year ended December 31, 2006, an increase of $26.1 million, or 32.4%. Midstream depreciation and amortization increased $25.8 million due to the NTP, NTG and north Louisiana expansion project assets.

*Interest Expense.* Interest expense was $79.4 million for the year ended December 31, 2007 compared to $51.4 million for the year ended December 31, 2006, an increase of $28.0 million, or 54.4%. The increase relates primarily to an increase in debt outstanding as a result of acquisitions and other growth projects. Net interest expense consists of the following (in millions):

| | Years Ended December 31, | |
|---|---|---|
| | 2007 | 2006 |
| Senior notes | $ 33.4 | $ 23.6 |
| Credit facility | 47.2 | 30.1 |
| Capitalized interest | (4.8) | (5.4) |
| Mark to market interest rate swaps | 1.1 | (0.1) |
| Realized interest rate swaps | (0.7) | — |
| Interest income | (0.7) | (1.1) |
| Other | 3.9 | 4.3 |
| Total | $ 79.4 | $ 51.4 |

*Discontinued Operations.* Discontinued operations were $6.5 million for the year ended December 31, 2007 compared to $7.3 million for the year ended December 31, 2006. In November 2008, we sold our undivided 12.4% interest in the Seminole gas processing plant to an unrelated third party.

**Critical Accounting Policies**

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as the accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules, and the use of judgment to the specific set of circumstances existing in our business. Compliance with the rules necessarily involves reducing a number of very subjective judgments to a quantifiable accounting entry or valuation. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. Our critical accounting policies are discussed below. See Note 2 of the Notes to Consolidated Financial Statements for further details on our accounting policies and a discussion of new accounting pronouncements.

*Revenue Recognition and Commodity Risk Management.* We recognize revenue for sales or services at the time the natural gas or NGLs are delivered or at the time the service is performed. We generally accrue one to two months of sales and the related gas purchases and reverse these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

We utilize extensive estimation procedures to determine the sales and cost of gas purchase accruals for each accounting cycle. Accruals are based on estimates of volumes flowing each month from a variety of sources. We use actual measurement data, if it is available, and will use such data as producer/shipper nominations, prior month average daily flows, estimated flow for new production and estimated end-user requirements (all adjusted for the estimated impact of weather patterns) when actual measurement data is not available. Throughout the month or two following production, actual measured sales and transportation volumes are received and invoiced and used in a process referred to as “actualization”. Through the actualization process, any estimation differences recorded through the accrual are reflected in the subsequent month’s accounting cycle when the accrual is reversed and actual amounts are recorded. Actual volumes purchased, processed or sold may differ from the estimates due to a variety of factors including, but not limited to: actual wellhead production or customer requirements being higher or lower than the amount nominated at the beginning of the month; liquids recoveries being higher or lower than estimated

because gas processed through the plants was richer or leaner than estimated; the estimated impact of weather patterns being different from the actual impact on sales and purchases; and pipeline maintenance or allocation causing actual deliveries of gas to be different than estimated. We believe that our accrual process for the one to two months of sales and purchases provides a reasonable estimate of such sales and purchases.

We engage in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas and natural gas liquids. We also manage our price risk related to future physical purchase or sale commitments by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance our future commitments and significantly reduce our risk to the movement in natural gas prices.

We use derivatives to hedge against changes in cash flows related to product prices and interest rate risks, as opposed to their use for trading purposes. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, requires that all derivatives and hedging instruments are recognized as assets or liabilities at fair value. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

We conduct "off-system" gas marketing operations as a service to producers on systems that we do not own. We refer to these activities as part of energy trading activities. In some cases, we earn an agency fee from the producer for arranging the marketing of the producer's natural gas. In other cases, we purchase the natural gas from the producer and enter into a sales contract with another party to sell the natural gas. The revenue and cost of sales for these activities are shown net in the statement of operations.

We manage our price risk related to future physical purchase or sale commitments for energy trading activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance future commitments and significantly reduce risk related to the movement in natural gas prices. However, we are subject to counter-party risk for both the physical and financial contracts. Our energy trading contracts qualify as derivatives, and we use mark-to-market accounting for both physical and financial contracts of the energy trading business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to energy trading activities are recognized in earnings as gain or loss on derivatives immediately.

*Impairment of Long-Lived Assets.* In accordance with Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we evaluate the long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

When determining whether impairment of one of our long-lived assets has occurred, we must estimate the undiscounted cash flows attributable to the asset. Our estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors, including but not limited to:

- changes in general economic conditions in regions in which our markets are located;
- the availability and prices of natural gas supply;
- our ability to negotiate favorable sales agreements;
- the risks that natural gas exploration and production activities will not occur or be successful;
- our dependence on certain significant customers, producers, and transporters of natural gas; and

- competition from other midstream companies, including major energy producers.

Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

*Depreciation Expense and Cost Capitalization.* Our assets consist primarily of natural gas gathering pipelines, processing plants, transmission pipelines and natural gas treating plants. We capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering and the costs of funds used in construction. Capitalized interest represents the cost of funds used to finance the construction of new facilities and is expensed over the life of the constructed assets through the recording of depreciation expense. We capitalize the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred.

We generally compute depreciation using the straight-line method over the estimated useful life of the assets. Certain assets such as land, NGL line pack and natural gas line pack are non-depreciable. The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets. As circumstances warrant, we may review depreciation estimates to determine if any changes are needed. Such changes could involve an increase or decrease in estimated useful lives or salvage values, which would impact future depreciation expense.

**Liquidity and Capital Resources**

*Cash Flows from Operating Activities.* Net cash provided by operating activities was $173.8 million, $114.8 million and $113.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. Income before non-cash income and expenses and changes in working capital for 2008, 2007 and 2006 were as follows (in millions):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Income before non-cash income and expenses | $160.9 | $138.9 | $88.3 |
| Changes in working capital | 12.9 | (24.0) | 24.7 |

The primary reason for the increased cash flow from income before non-cash income and expenses of $22.0 million from 2007 to 2008 was increased operating income from our expansions in north Texas and north Louisiana during 2007 and 2008. The primary reason for the increased cash flow from income before non-cash income and expenses of $50.6 million from 2006 to 2007 was increased operating income from our expansion in north Texas during 2006 and 2007.

*Cash Flows from Investing Activities.* Net cash used in investing activities was $186.8 million, $411.4 million and $885.8 million for the years ended December 31, 2008, 2007 and 2006, respectively. Our primary investing activities for 2008, 2007 and 2006 were capital expenditures and acquisitions, net of accrued amounts, as follows (in millions):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Growth capital expenditures | $ 257.3 | $ 403.7 | $ 308.8 |
| Acquisitions and asset purchases | — | — | 576.1 |
| Maintenance capital expenditures | 18.3 | 10.8 | 6.0 |
| Total | $ 275.6 | $ 414.5 | $ 890.9 |

Net cash invested in Midstream assets was $222.4 million for 2008, $385.8 million for 2007 and $746.7 million for 2006 (including $475.4 million related to the acquisition of assets from Chief). Net cash invested in Treating assets was $41.8 million for 2008, $23.5 million for 2007 and $86.8 million for 2006 (including $51.5 million related to the acquisition of Hanover assets). Net cash invested in other corporate assets was $11.4 million for 2008, $5.2 million for 2007 and $8.2 million for 2006.

Cash flows from investing activities for the years ended December 31, 2008, 2007 and 2006 also include proceeds from property sales of $88.8 million, $3.1 million and $5.1 million, respectively. Sales in 2008 primarily relate to the sale of interest in the Seminole gas processing plant. The 2007 and 2006 sales primarily related to sales of inactive properties.

*Cash Flows from Financing Activities.* Net cash provided by financing activities was $14.6 million, $295.9 million and $772.2 million for the years ended December 31, 2008, 2007 and 2006, respectively. Our financing activities primarily relate to funding of capital expenditures and acquisitions. Our financings have primarily consisted of borrowings under our bank credit facility, borrowings under capital lease obligations, equity offerings and senior note issuances for 2008, 2007 and 2006 as follows (in millions):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Net borrowings under bank credit facility | $ 50.0 | $ 246.0 | $ 166.0 |
| Senior note issuances (net of repayments) | (9.4) | (9.4) | 298.5 |
| Net borrowings under capital lease obligations | 23.9 | 3.6 | — |
| Common unit offerings(1) | 101.9 | 58.8 | — |
| Senior subordinated unit offerings(1) | — | 102.6 | 368.3 |

(1) Includes our general partner's proportionate contribution and net of costs associated with the offering.

Distributions to unitholders and our general partner represent our primary use of cash in financing activities. Unless prohibited by our bank credit facility, we will distribute all available cash, as defined in our partnership agreement, within 45 days after the end of each quarter. Total cash distributions made during the last three years were as follows (in millions):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Common units | $ 94.4 | $ 49.8 | $ 39.7 |
| Subordinated units | 2.8 | 11.9 | 16.1 |
| General partner | 41.2 | 24.8 | 20.4 |
| Total | $ 138.4 | $ 86.5 | $ 76.2 |

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility. Changes in drafts payable for 2008, 2007 and 2006 were as follows (in millions):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Increase (decrease) in drafts payable | $(7.4) | $(19.0) | $18.1 |

*Working Capital Deficit.* We had a working capital deficit of $32.9 million as of December 31, 2008, primarily due to drafts payable of $21.5 million as of the same date. Our 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 so receivable and payable balances at any month end my fluctuate significantly depending on the timing of these receipts and payments. In addition, although we strive to minimize our natural gas and NGLs 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. Our 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 and associated with our interest rate swap derivatives which may fluctuate significantly due to changes in interest rates. The changes in working capital during the years ended December 31, 2008, 2007 and 2006 are due to the impact of the fluctuations discussed above.

*Off-Balance Sheet Arrangements.* We had no off-balance sheet arrangements as of December 31, 2008 and 2007.

*April 2008 Sale of Common Units.* On April 9, 2008, we issued 3,333,334 common units in a private offering at $30.00 per unit, which represented an approximate 7% discount from the market price on such date. Crosstex Energy GP, L.P. made a general partner contribution of $2.0 million in connection with the issuance to maintain its 2% general partner interest.

*December 2007 Sale of Common Units.* On December 19, 2007, we issued 1,800,000 common units representing limited partner interests in the Partnership at a price of $33.28 per unit for net proceeds of $57.6 million. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $1.2 million in connection with the issuance to maintain its 2% general partner interest.

*March 2007 Sale of Senior Subordinated Series D Units.* On March 23, 2007, we issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests in a private offering for net proceeds of approximately $99.9 million. The senior subordinated series D units were issued at $25.80 per unit, which represented a discount of approximately 25% to the market value of common units on such date. The discount represented an underwriting discount plus the fact that the units would not receive a distribution nor be readily transferable for two years. Crosstex Energy GP, L.P. made a general partner contribution of $2.7 million in connection with this issuance to maintain its 2% general partner interest. Due to the decreased distribution with respect to the fourth quarter of 2008, the senior subordinated series D units will automatically convert into common units on March 23, 2009 at a ratio of 1.05 common units for each senior subordinated series D unit. The senior subordinated series D units are not entitled to distributions of available cash or allocations of net income/loss from us until March 23, 2009.

*June 2006 Sale of Senior Subordinated Series C Units.* On June 29, 2006, we issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests in a private equity offering for net proceeds of $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represented a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million in connection with this issuance to maintain its 2% general partner interest. The senior subordinated series C units automatically converted to common units February 16, 2008 at a ratio of one common unit for each senior subordinated series C unit. The senior subordinated series C units were not entitled to distributions of available cash until their conversion to common units.

***Sources of Liquidity in 2009 and Capital Requirements***

Historically we have been successful in accessing capital from both the equity market and financial institutions to fund the growth of our operations. However, due to the lack of liquidity in the financial and equity markets coupled with the decline in our Midstream operations, our access to capital is expected to be severely limited in 2009. We have significantly reduced our growth plans during 2009 and 2010 to operate within our existing capital structure.

One of the first steps we needed to accomplish to continue to operate within our existing capital structure was to amend the terms of our bank credit facility and senior secured note agreement to allow us to operate with a higher leverage ratio and a lower interest coverage ratio due to the anticipated decline in our operating income for 2009 and 2010 based on current economic conditions. We amended our bank credit facility and our senior secured note agreement in November 2008 and again in February 2009 to provide for terms that we expect will allow us to continue to operate our assets during the current difficult economic conditions. The terms of the amended agreements allow us to maintain a higher level of leverage and to maintain a lower interest coverage ratio but our interest costs will increase, our ability to incur additional indebtedness will be restricted when we are operating at higher leverage ratios and our ability to pay distributions will be prohibited until our leverage ratio is significantly lower and we repay the PIK notes. The PIK notes are due six months after the earlier of the refinancing or maturity of our bank credit facility. The terms of these agreements and our PIK notes are described more fully under "Description of Indebtedness."

We have lowered our distribution level from $0.63 per unit for the second quarter of 2008 to $0.50 per unit for the third quarter of 2008 and $0.25 per unit for the fourth quarter of 2008. As discussed above, the amended terms of our bank credit facility and senior secured note agreement restrict our ability to make distributions unless certain conditions are met. We do not expect that we will meet these conditions in 2009.

We have reduced our budgeted capital expenditures significantly for 2009. Total growth capital investments in the calendar year 2009 are currently anticipated to be approximately $100.0 million and primarily relate to capital projects in north Texas and Louisiana pursuant to contractual obligations with producers. We will use cash flow from operations and existing capacity under our bank credit facility to fund our reduced capital spending plan during 2009. Capital expenditures in future periods will be limited to cash flow from operating activities and to existing capacity under our bank credit facility. It is unlikely that we will be able to make any acquisitions based on the terms of our credit facility and our senior secured note agreement and the condition of the capital markets because we may only use Excess Proceeds, as defined under "Amendments to Credit Documents" below, from the incurrence of unsecured debt and the issuance of equity to make such acquisitions.

We have reduced our general and administrative expenses by reducing our work force by approximately 8.0% through the elimination of open positions and certain corporate positions and minimizing all non-essential costs. We have also reduced our operating expenses by reducing overtime and renegotiating certain contracts to reduce monthly costs and by eliminating some equipment rentals.

*Total Contractual Cash Obligations.* A summary of our total contractual cash obligations as of December 31, 2008 is as follows (in millions):

| | Payments Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | Total | 2009 | 2010 | 2011 | 2012 | 2013 | Thereafter |
| Long-Term Debt | $ 1,263.7 | $ 9.4 | $ 20.3 | $ 816.0 | $ 93.0 | $ 93.0 | $ 232.0 |
| Interest Payable on Fixed Long-Term Debt Obligations | 194.6 | 38.0 | 37.0 | 35.6 | 31.3 | 23.9 | 28.8 |
| Capital Lease Obligations | 32.8 | 3.3 | 3.2 | 3.2 | 3.2 | 3.2 | 16.7 |
| Operating Leases | 88.5 | 28.4 | 19.0 | 17.9 | 16.4 | 3.1 | 3.7 |
| Unconditional Purchase Obligations | 13.5 | 13.5 | — | — | — | — | — |
| FIN 48 Tax Obligations | 1.6 | 1.3 | 0.1 | 0.1 | 0.1 | — | — |
| Total Contractual Obligations | $ 1,594.7 | $ 93.9 | $ 79.7 | $ 872.8 | $ 143.9 | $ 123.2 | $ 281.2 |

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

The interest payable under our bank credit facility is not reflected in the above table because such amounts depend on outstanding balances and interest rates, which will vary from time to time. Based on balances outstanding and rates in effect at December 31, 2008, annual interest payments would be $30.6 million. The interest amounts also exclude estimates of the effect of our interest rate swap contracts.

The unconditional purchase obligations for 2009 relate to purchase commitments for equipment.

**Description of Indebtedness**

As of December 31, 2008 and 2007, long-term debt consisted of the following (in thousands):

| | 2008 | 2007 |
|---|---|---|
| Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2008 and 2007 were 6.33% and 6.71%, respectively | $ 784,000 | $ 734,000 |
| Senior secured notes, weighted average interest rates at December 31, 2008 and 2007 of 8.0% and 6.75%, respectively | 479,706 | 489,118 |
| | 1,263,706 | 1,223,118 |
| Less current portion | (9,412) | (9,412) |
| Debt classified as long-term | $ 1,254,294 | $ 1,213,706 |

*Credit Facility.* In September 2007, we increased borrowing capacity under the bank credit facility to $1.185 billion. The bank credit facility matures in June 2011. As of December 31, 2008, $850.4 million was outstanding under the bank credit facility, including $66.4 million of letters of credit, leaving approximately $334.6 million available for future borrowing.

Obligations under the bank credit facility are secured by first priority liens on all of our 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, and rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by our material 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.

On November 7, 2008, we entered into the Fifth Amendment and Consent (the "Fifth Amendment") to our credit facility with Bank of America, N.A., as administrative agent, and the banks and other parties thereto (the "Bank Lending Group"). The Fifth Amendment amended the agreement governing our credit facility to, among other things, (i) increase the maximum permitted leverage ratio we must maintain for the fiscal quarters ending December 31, 2008 through September 30, 2009, (ii) lower the minimum interest coverage ratio we must maintain for the fiscal quarter ending December 31, 2008 and each fiscal quarter thereafter, (iii) permit us to sell certain assets, (iv) increase the interest rate we pay on the obligations under the credit facility and (v) lower the maximum permitted leverage ratio we must maintain if we or our subsidiaries incur unsecured note indebtedness.

Due to the continued decline in commodity prices and the deterioration in the processing margins, we determined that there was a significant risk that the amended terms negotiated in November 2008 would not be sufficient to allow us to operate during 2009 without triggering a covenant default under our bank credit facility and the senior secured note agreement. On February 27, 2009, we entered into the Sixth Amendment to Fourth Amended and Restated Credit Agreement and Consent (the "Sixth Amendment") to our credit facility with the Bank Lending Group. Under the Sixth Amendment, borrowings will bear interest at our option at the administrative agent's reference rate plus an applicable margin or LIBOR plus an applicable margin. The applicable margins for the Partnership's interest rate and letter of credit fees vary quarterly based on the Partnership's leverage ratio as defined by the credit facility (the "Leverage Ratio" being generally computed as total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows beginning February 27, 2009:

| Leverage Ratio | Bank Reference Rate Advances(a) | LIBOR Rate Advances(b) | Letter of Credit Fees(c) | Commitment Fees(d) |
|---|---|---|---|---|
| Greater than or equal to 5.00 to 1.00 | 3.00% | 4.00% | 4.00% | 0.50% |
| Greater than or equal to 4.25 to 1.00 and less than 5.00 to 1.00 | 2.50% | 3.50% | 3.50% | 0.50% |
| Greater than or equal to 3.75 to 1.00 and less than 4.25 to 1.00 | 2.25% | 3.25% | 3.25% | 0.50% |
| Less than 3.75 to 1.00 | 1.75% | 2.75% | 2.75% | 0.50% |

(a) The applicable margins for the bank reference rate advances ranged from 0% to 0.25% under the bank credit facility prior to the Fifth and Sixth Amendments. The applicable margin for the bank reference rate advances was paid at the maximum rate of 2.00% under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(b) The applicable margins for the LIBOR rate advances ranged from 1.00% to 1.75% under the bank credit facility prior to the Fifth and Sixth Amendments. The applicable margin for the bank reference rate advances was paid at the maximum rate of 3.00% under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(c) The letter of credit fees ranged from 1.00% to 1.75% per annum plus a fronting fee of 0.125% per annum under the bank credit facility prior to the Fifth and Sixth Amendments. The letter of credit fees were paid at the maximum rate of 3.00% per annum in addition to the fronting fee under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(d) The commitment fees ranged from 0.20% to 0.375% per annum on the unused amount of the credit facility under the bank credit facility prior to the Fifth and Sixth Amendments. The commitment fees were paid at the maximum rate of 0.50% per annum under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

The Sixth Amendment also sets a floor for the LIBOR interest rate of 2.75% per annum, which means, effective as of February 27, 2009, borrowings under the bank credit facility accrue interest at the rate of 6.75% based on the LIBOR rate in effect on such date and our current leverage ratio. Based on our forecasted leverage ratios for 2009, we expect the applicable margins to be at the high end of these ranges for our interest rate and letter of credit fees.

Pursuant to the Sixth Amendment, we must pay a leverage fee if we do not prepay debt and permanently reduce the banks' commitments by the cumulative amounts of $100.0 million on September 30, 2009, $200.0 million on December 31, 2009, and $300.0 million on March 31, 2010. If we fail to meet any de-leveraging target, we must pay a leverage fee on such date, equal to the product of the total amounts outstanding under our bank credit facility and the senior secured note agreement on such date, and 1.0% on September 30, 2009, 1.0% on December 31, 2009 and 2.0% on March 31, 2010. This leverage fee will accrue on the applicable date, but not be payable until we refinance our bank credit facility.

Under the Sixth Amendment, the maximum Leverage Ratio (measured quarterly on a rolling four-quarter basis) is as follows:

- 7.25 to 1.00 for the fiscal quarter ending March 31, 2009;
- 8.25 to 1.00 for the fiscal quarters ending June 30, 2009 and September 30, 2009;
- 8.50 to 1.00 for the fiscal quarter ending December 31, 2009;
- 8.00 to 1.00 for the fiscal quarter ending March 31, 2010;
- 6.65 to 1.00 for the fiscal quarter ending June 30, 2010;
- 5.25 to 1.00 for the fiscal quarter ending September 30, 2010;
- 5.00 to 1.00 for the fiscal quarter ending December 31, 2010;
- 4.50 to 1.00 for any fiscal quarter ending March 31, 2011 through March 31, 2012; and
- 4.25 to 1.00 for any fiscal quarter ending June 30, 2012 and thereafter.

The minimum cash interest coverage ratio (as defined in the agreement, measured quarterly on a rolling four-quarter basis) is as follows under the Sixth Amendment:

- 1.75 to 1.00 for the fiscal quarters ending March 31, 2009;
- 1.50 to 1.00 for the fiscal quarter ending June 30, 2009;
- 1.30 to 1.00 for the fiscal quarter ending September 30, 2009;
- 1.15 to 1.00 for the fiscal quarter ending December 31, 2009;
- 1.25 to 1.00 for the fiscal quarter ending March 31, 2010;
- 1.50 to 1.00 for the fiscal quarter ending June 30, 2010;
- 1.75 to 1.00 for any fiscal quarter ending September 30, 2010 and December 31, 2010; and
- 2.50 to 1.00 for any fiscal quarter ending March 31, 2011 and thereafter.

Under the Sixth Amendment, no quarterly distributions may be paid to unitholders unless the PIK notes have been repaid and the Leverage Ratio is less than 4.25 to 1.00. If the Leverage Ratio is between 4.00 to 1.00 and 4.25 to 1.00, we may make the minimum quarterly distribution of up to $0.25 per unit if the PIK notes have been repaid. If the Leverage Ratio is less than 4.00 to 1.00, we may make quarterly distributions to unitholders from available cash as provided by our partnership agreement if the PIK notes have been repaid. The PIK notes are due six months after the earlier of the refinancing or maturity of our bank credit facility. In order to repay the PIK notes prior to their scheduled maturity, we will need to amend or refinance our bank credit facility. Based on our forecasted leverage ratios for 2009 and our near term ability to refinance our bank credit facility, we do not anticipate making quarterly distributions in 2009 other than the distribution paid in February 2009 related to fourth quarter 2008 operating results.

The Sixth Amendment also limits our annual capital expenditures (excluding maintenance capital expenditures) to $120.0 million in 2009 and $75.0 million in 2010 and each year thereafter (with unused amounts in any year being carried forward to the next year). It is unlikely that we will be able to make any acquisitions based on the terms of our amended credit facility and the current condition of the capital markets because we may only use a portion of the proceeds from the incurrence of unsecured debt and the issuance of equity to make such acquisitions.

The Sixth Amendment also eliminated the accordion in our bank credit facility, which previously had permitted us to increase commitments thereunder by certain amounts if any bank was willing to undertake such commitment increase.

The Sixth Amendment also revised the terms for mandatory repayment of outstanding indebtedness from asset sales and proceeds from incurrence of unsecured debt and equity issuances. Proceeds from debt issuances and from equity issuances not required to prepay indebtedness are considered to be "Excess Proceeds" under the amended bank credit agreement. We may retain all Excess Proceeds. The following table sets forth the amended prepayment terms:

| Leverage Ratio* | % of Net Proceeds from Asset Sales Required for Repayment | % of Net Proceeds from Debt Issuances Required for Prepayment | % of Net Proceeds from Equity Issuance Required for Prepayment |
|---|---|---|---|
| Greater than or equal to 4.50 | 100% | 100% | 50% |
| Greater or equal to 3.50 and Less Than 4.50 | 100% | 50% | 25% |
| Less than 3.5 | 100% | 0% | 0% |

* The Leverage Ratio is to be adjusted to give effect to proceeds from debt or equity issuance and the use of such proceeds for each proportional level of Leverage Ratio.

The prepayments are to be applied pro rata based on total debt (including letter of credit obligations) outstanding under the bank credit agreement and the total debt outstanding under the note agreement described below. Any prepayments of advances on the bank credit facility from proceeds from asset sales, debt or equity issuances will permanently reduce the borrowing capacity or commitment under the facility in an amount equal to 100% of the amount of the prepayment. Any such commitment reduction will not reduce the banks' $300.0 million commitment to issue letters of credit.

In addition, the bank credit facility contains various covenants that, among other restrictions, limit our ability to:

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- change the nature of our business;
- enter into certain commodity contracts;

- make certain amendments to our or the operating partnership's partnership agreement; and
- engage in transactions with affiliates.

Each of the following will be an event of default under the bank credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;
- certain judgments against us or any of our subsidiaries, in excess of certain allowances;
- certain ERISA events involving us or our subsidiaries;
- bankruptcy or other insolvency events;
- a change in control (as defined in the credit agreement); and
- the failure of any representation or warranty to be materially true and correct when made.

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under our bank credit facility will immediately become due and payable. If any other event of default exists under the bank credit facility, the lenders may accelerate the maturity of the obligations outstanding under the bank credit facility and exercise other rights and remedies.

We are subject to interest rate risk on our credit facility and have entered into interest rate swaps to reduce this risk. See Note 13 to the financial statements for a discussion of interest rate swaps.

*Senior Secured Notes.* We entered into a master shelf agreement with an institutional lender in 2003 that was amended in subsequent years to increase availability under the agreement, pursuant to which we issued the following senior secured notes (dollars in thousands):

| Month Issued | Amount | Interest Rate(1) | Maturity | Principal Payment Terms |
|---|---|---|---|---|
| June 2003(2) | $ 30,000 | 9.45% | 7 years | Quarterly payments of $1,765 from June 2006-June 2010 |
| July 2003(2) | 10,000 | 9.38% | 7 years | Quarterly payments of $588 from July 2006-July 2010 |
| June 2004 | 75,000 | 9.46% | 10 years | Annual payments of $15,000 from July 2010-July 2014 |
| November 2005 | 85,000 | 8.73% | 10 years | Annual payments of $17,000 from November 2010-December 2014 |
| March 2006 | 60,000 | 8.82% | 10 years | Annual payments of $12,000 from March 2012-March 2016 |
| July 2006 | 245,000 | 8.46% | 10 years | Annual payments of $49,000 from July 2012-July 2016 |
| Total Issued | 505,000 | | | |
| Principal repaid | (25,294) | | | |
| Balance as of December 31, 2008 | $ 479,706 | | | |

(1) Interest rates have been adjusted to give effect to the 2% interest rate increase under the February 27, 2009 amendment described below.

(2) Principal repayments were $19.4 million and $5.9 million on the June 2003 and July 2003 notes, respectively.

On November 7, 2008, we amended our senior secured note agreement governing our senior secured notes to, among other things, (i) modify the maximum permitted leverage ratio and lower the minimum interest coverage ratio we must maintain consistent with the ratios under the Fifth Amendment to the bank credit facility, (ii) permit

us to sell certain assets and (iii) increase the interest rate we pay on the senior secured notes. The interest rate we paid on the senior secured notes increased by 1.25% for the fourth quarter of 2008 due to this amendment.

The covenant and terms of default for the senior secured notes are substantially the same as the covenants and default terms under our bank credit facility, and therefore the agreement governing the senior secured notes also required amendment in 2009. On February 27, 2009, we amended our senior note agreement to (i) increase the maximum permitted leverage ratio and to lower the minimum interest coverage ratio we must maintain consistent with the ratios under the Sixth Amendment to the bank credit facility, (ii) revise the mandatory prepayment terms consistent with the terms under the Sixth Amendment to the bank credit facility, (iii) increase the interest rate we pay on the senior secured notes and (iv) provide for the payment of a leverage fee consistent with the terms of the bank credit facility. Commencing February 27, 2009 the interest rate we pay in cash on all of the senior secured notes will increase by 2.25% per annum over the comparative interest rates under the senior note agreement prior to the November and February amendments. As a result of this rate increase, the weighted average cash interest rate of the outstanding balance on the senior secured notes is approximately 9.25% as of February 2009.

Under the amended senior secured notes agreement, the senior secured notes will accrue additional interest of 1.25% per annum of the senior secured note (the "PIK notes") in the form of an increase in the principal amount unless our leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter. All PIK notes will be payable six months after the maturity of our bank credit facility, which is currently scheduled to mature in June 2011, or six months after refinancing of such indebtedness if prior to the maturity date.

Per the terms of the amended senior notes agreement, commencing on the date we refinance our bank credit facility, the interest rate payable in cash on our senior secured notes will increase by 1.25% per annum for any quarter if our leverage ratio as of the most recently ended fiscal quarter was greater than or equal to 4.25 to 1.00. In addition, commencing on June 30, 2012, the interest rate payable in cash on our senior secured notes will increase by 0.50% per annum for any quarter if our leverage as of the most recently ended fiscal quarter was greater than or equal to 4.00 to 1.00, but this incremental interest will not accrue if we are paying the incremental 1.25% per annum of interest described in the preceding sentence.

These notes represent our senior secured obligations and will rank *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with our obligations under the credit facility, by first priority liens on all of our material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all our equity interests in substantially all of our subsidiaries. The senior secured notes are guaranteed by our material subsidiaries.

The senior secured notes issued in 2003 are redeemable, at our option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the senior secured note agreement. The senior secured notes issued in 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance.

If an event of default resulting from bankruptcy or other insolvency events occurs, the senior secured notes will become immediately due and payable. If any other event of default occurs and is continuing, holders of at least 50.1% in principal amount of the outstanding notes may at any time declare all the notes then outstanding to be immediately due and payable. If an event of default relating to the nonpayment of principal, make-whole amounts or interest occurs, any holder of outstanding notes affected by such event of default may declare all the notes held by such holder to be immediately due and payable.

The senior secured note agreement relating to the notes contains substantially the same covenants and events of default as our bank credit facility.

We were in compliance with all debt covenants at December 31, 2008 and 2007 and expect to be in compliance with debt covenants for the next twelve months.

*Intercreditor and Collateral Agency Agreement.* In connection with the execution of the senior secured note agreement, the lenders under our bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by us and our

subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under our bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under our bank credit facility, holders of our senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under our bank credit facility and the senior secured note agreement. On February 27, 2009, the holders of the Partnership's senior secured notes and a majority of the banks under its bank credit facility entered into an amendment to the Intercreditor and Collateral Agency Agreement, which provides that the PIK notes and certain treasury management obligations will be secured by the collateral for its bank credit facility and the senior secured notes, but only paid with proceeds of collateral after obligations under its bank credit facility and the senior secured notes are paid in full.

**Credit Risk**

Risks of nonpayment and nonperformance by our customers are a major concern in our business. We are subject to risks of loss resulting from nonpayment or nonperformance by our customers and other counterparties, such as our lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations and reduce our ability to make distributions to our unitholders. Many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Recently, there has been a significant decline in the credit markets and the availability of credit. Additionally, many of our customers' equity values have substantially declined. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction in our customers' liquidity and ability to make payments or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us.

**Inflation**

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry has experienced an increase in labor and material costs during the 2007 year and the first half of 2008, although these increases did not have a material impact on our results of operations for the periods presented. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

**Environmental**

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe we are in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us, see Item 1. "Business — Environmental Matters."

**Contingencies**

On November 15, 2007, Crosstex Processing received a demand letter from Denbury asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. The claim arises from a contract under which Crosstex Processing processed natural gas owned or controlled by Denbury in north Texas. Denbury contends that Crosstex Processing breached the Processing Contract by failing to build a processing plant of a certain size and design, resulting in Crosstex Processing's failure to properly process the gas over a ten month period. Denbury also alleges that Crosstex Processing failed to provide specific notices required under the Processing Contract. On December 4, 2007 and again on February 14, 2008, Denbury sent Crosstex Processing letters demanding that its claim be arbitrated pursuant to an arbitration provision in the Processing Contract. On April 15, 2008, the parties mediated the matter unsuccessfully. On December 4, 2008, Denbury initiated formal arbitration proceedings against Crosstex Processing, Crosstex Energy Services, L.P., Crosstex North Texas

Gathering, L.P., and Crosstex Gulf Coast Marketing, Ltd., seeking $11.4 million and additional unspecified damages. On December 23, 2008, Crosstex Processing filed an answer denying Denbury's allegations and a counterclaim seeking a declaratory judgment that its processing plant is uneconomic pursuant to the terms of the Processing Contract, allowing cancellation of the contract. Crosstex Energy, Crosstex Marketing, and Crosstex Gathering also filed an answer denying Denbury's allegations and asserting that they are improper parties as Denbury's claim is for breach of the Processing Contract and none of these entities is a party to that agreement. Crosstex Gathering also filed a counterclaim seeking approximately $40.0 million in damages for the value of the NGLs it is entitled to under its Gas Gathering Agreement with Denbury. Once the three-person arbitration panel has been named and cleared conflicts, the arbitration panel will hold a preliminary conference with the parties to set a date for the final hearing and other case deadlines and to establish discovery limits. Although it is not possible to predict with certainty the ultimate outcome of this matter, we do not believe this will have a material adverse effect on our consolidated results of operations or financial position.

The Partnership (or its subsidiaries) is defending eleven lawsuits filed by owners of property located near processing facilities or compression facilities constructed by us as part of our systems in north Texas. 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. At this time, five cases are set for trial during 2009. The remaining cases have not yet been set for trial. Discovery is underway. Although it is not possible to predict the ultimate outcomes of these matters, we do not believe that these claims will have a material adverse impact on our consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed us approximately $6.2 million, including approximately $3.9 million for June 2008 sales and approximately $2.2 million for July 2008 sales. We believe the July sales of $2.2 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to us for an administrative claim in the amount of approximately $2.2 million but the allowance of the administrative claim status is still subject to approval of the bankruptcy court in accordance with the administrative claim allowance procedures order in the case. We evaluated these receivables for collectability and provided a valuation allowance of $3.1 million during 2008.

**Recent Accounting Pronouncements**

In October 2008, as a result of the recent credit crisis, the FASB issued FSP No. FAS 157-3, "*Determining the Fair Value of a Financial Asset in a Market That is Not Active"* ("FSP FAS 157-3"). FSP FAS 157-3 clarifies the application of SFAS No. 157 in a market that is not active and provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. FSP FAS 157-3 is effective upon issuance, for companies that have adopted SFAS No. 157. The Partnership has evaluated the FSP and determined that this standard has no impact on its results of operations, cash flows or financial position for this reporting period.

In June 2008, the Financial Accounting Standards Board ("FASB") issued Staff Position FSP EITF 03-6-1 (the "FSP") which requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in EITF Issue No. 03-6, "Participating Securities and the Two-Class Method under FASB Statement No. 128," and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB Statement No. 128, *Earnings per Share.* The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Upon adoption, the Partnership will consider restricted units with nonforfeitable distribution rights in the calculation of earnings per unit and will adjust all prior reporting periods retrospectively to conform to the requirements, although the impact should not be material.

In February 2007, the FASB issued SFAS No. 159, *"Fair Value Option for Financial Assets and Financial Liabilities-Including an amendment to FASB Statement No. 115"* ("SFAS 159"). SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for

which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 was adopted effective January 1, 2008 and did not have a material impact on our financial statements.

In December 2007, the FASB issued SFAS No. 141R, *"Business Combinations"* ("SFAS 141R") and SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements"* ("SFAS 160"). SFAS 141R requires most identifiable assets, liabilities, noncontrolling interests and goodwill acquired in a business combination to be recorded at "full fair value." The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under SFAS 141R, all business combinations will be accounted for by applying the acquisition method. SFAS 141R is effective for periods beginning on or after December 15, 2008. SFAS 160 will require noncontrolling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for noncontrolling interests and transactions with noncontrolling interest holders in consolidated financial statements. SFAS 160 is effective for periods beginning on or after December 15, 2008 and will be applied prospectively to all noncontrolling interests, including any that arose before the effective date, except that comparative period information must be recast to classify noncontrolling interests in equity, attribute net income and other comprehensive income to noncontrolling interests and provide other disclosures required by SFAS 160.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* ("SFAS No. 162"). SFAS No. 162 is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS No. 162 is effective for fiscal years beginning after November 15, 2008. The Partnership is currently evaluating the potential impact, if any, of the adoption of SFAS No. 162 on our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, *"Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133"* ("SFAS 161"). SFAS 161 requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under SFAS 133 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. SFAS 161 is effective for fiscal years beginning after November 15, 2008. The principal impact to the Partnership will be to require expanded disclosure regarding derivative instruments.

**Disclosure Regarding Forward-Looking Statements**

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included in this Form 10-K constitute forward-looking statements, including but not limited to statements identified by the words "may," "will," "should," "plan," "predict," "anticipate," "believe," "intend," "estimate" and "expect" and similar expressions. 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 the specific uncertainties discussed elsewhere in this Form 10-K, the risk factors set forth in "Item 1A. Risk Factors" 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 7A.** ***Quantitative and Qualitative Disclosures about Market Risk***

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

**Interest Rate Risk**

We are exposed to interest rate risk on our variable rate bank credit facility. At December 31, 2008 and 2007, our bank credit facility had outstanding borrowings of $784.0 million and $734.0 million, respectively, which approximated fair value. We manage a portion of our interest rate exposure on our variable rate debt by utilizing interest rate swaps, which allow us to convert a portion of variable rate debt into fixed rate debt. In January 2008, we amended our existing interest rate swaps covering $450.0 million of the variable rate debt to extend the period by one year (coverage periods end from November 2010 through October 2011) and reduce the interest rates to a range of 4.38% to 4.68%. In September 2008, we entered into additional interest rate swaps covering the $450.0 million that converted the floating rate portion of the original swaps from three month LIBOR to one month LIBOR. In addition, we entered into one new interest rate swap in January 2008 covering $100.0 million of the variable rate debt for a period of one year at an interest rate of 2.83%. As of December 31, 2008, the fair value of these interest rate swaps was reflected as a liability of $35.5 million ($17.1 million in net current liabilities and $18.4 million in long-term liabilities) on our financial statements. We estimate that a 1% increase or decrease in the interest rate would increase or decrease the fair value of these interest rate swaps by approximately $22.4 million. Considering the interest rate swaps and the amount outstanding on our bank credit facility as of December 31, 2008, we estimate that a 1% increase or decrease in the interest rate would change our annual interest expense by approximately $2.3 million for periods when the entire portion of the $550.0 million of interest rate swaps are outstanding and $7.8 million for annual periods after 2011 when all the interest rate swaps lapse.

At December 31, 2008 and 2007, we had total fixed rate debt obligations of $479.7 million and $489.1 million, respectively, consisting of our senior secured notes with a weighted average interest rate of 8.0%. The fair value of these fixed rate obligations was approximately $374.4 million and $500.5 million as of December 31, 2008 and 2007, respectively. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of the fixed rated debt (our senior secured notes) by $15.2 million based on the debt obligations as of December 31, 2008.

**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") in processing. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when our margins are negative under our current processing margin contracts primarily through our ability to bypass processing when it is not profitable for us, or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.

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

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

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

| | Years Ended December 31, | |
|---|---|---|
| | 2008 | 2007 |
| Gathering and transportation margin | 49.3% | 41.5% |
| Gas processing margins: | | |
| Processing margin | 17.0% | 18.4% |
| Percent of liquids | 14.2% | 19.6% |
| Fee based | 7.5% | 8.1% |
| Total gas processing | 38.7% | 46.1% |
| Treating margin | 12.0% | 12.4% |
| Total | 100.0% | 100.0% |

We have hedges in place at December 31, 2008 covering liquids volumes we expect to receive under percent of liquids (POL) contracts as set forth in the following table. The relevant payment index price is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

| Period | Underlying | Notional Volume | | We Pay (In thousands) | We Receive | Fair Value Asset/(Liability) |
|---|---|---|---|---|---|---|
| January 2009-December 2009 | Ethane | 114 | (MBbls) | Index | $ 0.760 - $0.8275/gal | $ 1,751 |
| January 2009-December 2009 | Propane | 113 | (MBbls) | Index | $ 1.39 - $1.46/gal | 3,577 |
| January 2009-December 2009 | Iso Butane | 31 | (MBbls) | Index | $ 1.7375 - $1.78/gal | 1,222 |
| January 2009-December 2009 | Normal Butane | 37 | (MBbls) | Index | $ 1.705- $1.765/gal | 1,475 |
| January 2009-December 2009 | Natural Gasoline | 86 | (MBbls) | Index | $ 2.1275-$2.1575/gal | 4,553 |
| | | | | | | $ 12,578 |

We have hedged our exposure to declines in prices for NGL volumes produced for our account. The NGL volumes hedged, as set forth above, focus on our POL contracts. We hedge our POL exposure based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total POL volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. We have hedged 44% of our hedgeable volumes at risk through the end of 2009 (20% of total volumes at risk through the end of 2009). We currently have not hedged any of our processing margin volumes for 2009.

We are also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transport services. Approximately 4.0% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices. We have hedged 34% of our natural gas volumes at risk through the end of 2009.

Set forth in the table below is the volume of the natural gas purchased and sold at a fixed discount or premium to the index price and at a percentage discount or premium to the index price for our principal gathering and transmission systems and for our commercial services business for the year ended December 31, 2008.

| | Years Ended December 31, 2008 | | | |
|---|---|---|---|---|
| | Gas Purchased | | Gas Sold | |
| Asset or Business | Fixed Amount to Index | Percentage of Index | Fixed Amount to Index | Percentage of Index |
| | (In thousands of MMBtu's) | | | |
| LIG system(2) | 248,715 | 3,955 | 252,670 | — |
| South Texas system(1) | 124,888 | 11,892 | 126,969 | — |
| North Texas system | 84,311 | 4,577 | 88,339 | — |
| Other assets and activities(1) | 78,373 | 2,160 | 15,456 | — |

1) Gas sold is less than gas purchased due to production of NGLs on some of the assets included in the south Texas system and other assets.

2) LIG plants purchase the gathering system plant thermal reduction (PTR).

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

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

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

As of December 31, 2008, 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 $16.0 million. The aggregate effect of a hypothetical 10% increase in gas and NGLs prices would result in a decrease of approximately $1.4 million in the net fair value asset of these contracts as of December 31, 2008.

**Item 8.** ***Financial Statements and Supplementary Data***

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required by this Item are set forth on pages F-1 through F-47 of this Report and are incorporated herein by reference.

**Item 9.** ***Changes in and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

**Item 9A.** ***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 concluded that our disclosure controls and procedures were effective as of December 31, 2008 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

**(b) Changes in Internal Control Over Financial Reporting**

There has been no change in our internal controls over financial reporting that occurred in the three months ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

**Internal Control Over Financial Reporting**

See "Management's Report on Internal Control over Financial Reporting" on page F-2.

**Item 9B.** ***Other Information***

On February 27, 2009, we entered into the Sixth Amendment to our Fourth Amended and Restated Credit Agreement and Consent with Bank of America, N.A. and the other lenders party thereto (the "Credit Agreement Amendment") and Letter Amendment No. 4 to our Amended and Restated Note Purchase Agreement with the holders of our senior secured promissory notes and other parties thereto (the "Note Purchase Agreement Amendment"). We have filed the Credit Agreement Amendment and the Note Purchase Agreement Amendment as Exhibits 10.6 and 10.11, respectively, to this Form 10-K. See "Item 1. Business — Amendments to Credit Documents" and Item 7. — Management's Discussion and Analysis of Financial Condition and Results of Operations — Description of Indebtedness" for more information.

**PART III**

**Item 10.** ***Directors, Executive Officers and Corporate Governance***

As is the case with many publicly traded partnerships, we do not have officers, directors or employees. Our operations and activities are managed by the general partner of our general partner, Crosstex Energy GP, LLC. Our operational personnel are employees of the Operating Partnership. References to our general partner, unless the context otherwise requires, includes Crosstex Energy GP, LLC. References to our officers, directors and employees are references to the officers, directors and employees of Crosstex Energy GP, LLC or the Operating Partnership.

Unitholders do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to the unitholders, as limited by our partnership agreement. As general partner, Crosstex Energy GP, L.P. is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Whenever possible, our general partner intends to incur indebtedness or other obligations on a non-recourse basis.

The following table shows information for the directors and executive officers of Crosstex Energy GP, LLC. Executive officers and directors serve until their successors are duly appointed or elected.

| Name | Age | Position with Crosstex Energy GP, LLC |
|---|---|---|
| Barry E. Davis | 47 | President, Chief Executive Officer and Director |
| Robert S. Purgason | 52 | Executive Vice President — Chief Operating Officer |
| William W. Davis | 55 | Executive Vice President and Chief Financial Officer |
| Joe A. Davis | 48 | Executive Vice President, General Counsel and Secretary |
| Rhys J. Best** | 62 | Chairman of the Board and Member of the Conflicts Committee and Compensation Committee |
| Leldon E. Echols** | 53 | Director and Member of the Audit Committee* |
| Bryan H. Lawrence | 66 | Director |
| Sheldon B. Lubar** | 79 | Director and Member of the Governance Committee* |
| Cecil E. Martin** | 67 | Director and Member of the Audit Committee and Compensation Committee* |
| Kyle D. Vann** | 61 | Director and Member of the Conflicts Committee* and Audit Committee |

* Denotes chairman of committee.

** Denotes independent director.

*Barry E. Davis*, President, Chief Executive Officer and Director, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of our predecessor. Mr. Davis has served as director since our initial public offering in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University. Mr. Davis also serves as the Chairman of the Board for Crosstex Energy, Inc.

*Robert S. Purgason*, Executive Vice President — Chief Operating Officer, joined Crosstex in October 2004 as Senior Vice President — Treating Division to lead the Treating Division and was promoted to Executive Vice President — Chief Operating Officer in November 2006. Prior to joining Crosstex, Mr. Purgason spent 19 years with Williams Companies in various senior business development and operational roles. He was most recently Vice President of the Gulf Coast Region Midstream Business Unit. Mr. Purgason began his career at Perry Gas Companies in Odessa working in all facets of the treating business. Mr. Purgason received a B.S. degree in Chemical Engineering with honors from the University of Oklahoma.

*William W. Davis*, Executive Vice President and Chief Financial Officer, joined our predecessor in September 2001, and has over 25 years of finance and accounting experience. For more than the last six years Mr. Davis has served as our Chief Financial Officer. Prior to joining our predecessor, Mr. Davis held various positions with Sunshine Mining and Refining Company from 1983 to September 2001, including Vice President — Financial Analysis from 1983 to 1986, Senior Vice President and Chief Accounting Officer from 1986 to 1991 and Executive Vice President and Chief Financial Officer from 1991 to 2001. In addition, Mr. Davis served as Chief Operating Officer in 2000 and 2001. Mr. Davis graduated magna cum laude from Texas A&M University with a B.B.A. in Accounting and is a Certified Public Accountant. Mr. Davis is not related to Barry E. Davis or Joe A. Davis.

*Joe A. Davis,* Executive Vice President, General Counsel and Secretary, joined Crosstex in October 2005. He began his legal career with the Dallas firm of Worsham Forsythe, which merged with the international law firm of Hunton & Williams in 2002. Most recently, he served as a partner in the firm's Energy Practice Group, and served on the firm's Executive Committee. Mr. Davis specialized in facility development, sales, acquisitions and financing for the energy industry, representing entrepreneurial start up/development companies, growth companies, large

public corporations and large electric and gas utilities. He received his J.D. from Baylor Law School in Waco and his B.S. degree from the University of Texas in Dallas. Mr. Davis is not related to Barry E. Davis or William W. Davis.

*Rhys J. Best* joined Crosstex Energy GP, LLC as a director in June 2004 and became Chairman of the Board in February 2009. Mr. Best was Chairman and Chief Executive Officer of Lone Star Technologies, Inc., until its merger into United States Steel Company in June of 2007. Mr. Best held the position of Chief Executive Officer from June 1998 and he assumed the additional responsibilities of Chairman in January 1999. He began his career at Lone Star as the President and Chief Executive Officer of Lone Star Steel Company, a position he held for eight years before becoming President and Chief Operating Officer of the parent company in 1997. Before joining Lone Star, Mr. Best held several leadership positions in the banking industry. Mr. Best also serves on the boards of Trinity Industries (NYSE: TRN), Austin Industries, Inc., and McJunkin Red Man Corporation. Trinity is a leading diversified holding company with a subsidiary group that provides a variety of products and services for the transportation, industrial, construction and energy sectors. Austin Industries and McJunkin Red Man are private companies in the construction and energy sectors. Mr. Best graduated from the University of North Texas with a Bachelor of Business degree and later earned a Masters of Business Administration Degree at Southern Methodist University.

*Leldon E. Echols* joined Crosstex Energy GP, LLC as a director in January 2008. Mr. Echols is a private investor. Mr. Echols also currently serves as an independent director of Trinity Industries, Inc. (NYSE: TRN), a leading diversified holding company with a subsidiary group that provides a variety of products and services for the transportation, industrial, construction and energy sectors, and Holly Corporation (NYSE: HOC), an independent petroleum refiner and marketer. Mr. Echols brings 30 years of financial and business experience to Crosstex. After 22 years with the accounting firm Arthur Andersen LLP, which included serving as managing partner of the firm's audit and business advisory practice in North Texas, Colorado and Oklahoma, Mr. Echols spent six years with Centex Corporation as executive vice president and chief financial officer. He retired from Centex Corporation in June 2006. Mr. Echols is also a member of the boards of directors of two private companies, Roofing Supply Group Holdings, Inc. and Colemont Corporation. He also served on the board of TXU Corp. (NYSE: TXU) where he chaired the Audit Committee and was a member of the Strategic Transactions Committee until the completion of the private equity buyout of TXU in October 2007. Mr. Echols earned a Bachelor of Science degree in accounting from Arkansas State University and is a Certified Public Accountant. He is a member of the American Institute of Certified Public Accountants and the Texas Society of CPAs. Mr. Echols has also served as a director of Crosstex Energy, Inc. since January 2008.

*Bryan H. Lawrence*, joined Crosstex Energy GP, LLC as a director upon the completion of our initial public offering in December 2002 and served as Chairman of the Board until May 2008. Mr. Lawrence is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships, which make investments in companies engaged in the energy industry. The Yorktown partnerships were formerly affiliated with the investment firm of Dillon, Read & Co. Inc., where Mr. Lawrence had been employed since 1966, serving as a Managing Director until the merger of Dillon Read with SBC Warburg in September 1997. Mr. Lawrence also serves as a director of Hallador Petroleum Company (OTC BB: HPCO.OB), Star Gas Partners L.P. (NYSE: SGU), Winstar Resources Ltd. (a Canadian public company), Approach Resources, Inc. (NASDAQ: AREX) and certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests. Mr. Lawrence is a graduate of Hamilton College and also has an M.B.A. from Columbia University.

*Sheldon B. Lubar* joined Crosstex Energy GP, LLC as a director upon the completion of our initial public offering in December 2002. Mr. Lubar has been Chairman of the Board of Lubar & Co. Incorporated, a private investment and venture capital firm he founded, since 1977. He was Chairman of the Board of Christiana Companies, Inc., a logistics and manufacturing company, from 1987 until its merger with Weatherford International in 1995. Mr. Lubar also serves as a director of Weatherford International, Inc. (NYSE: WFT), an energy services company, and Approach Resources, Inc. (NASDAQ: AREX). Mr. Lubar has also served as a director of Crosstex Energy, Inc. since January 2004. Mr. Lubar holds a bachelor's degree in Business Administration and a Law degree from the University of Wisconsin — Madison. He was awarded an honorary Doctor of Commercial Science degree from the University of Wisconsin — Milwaukee.

*Cecil E. Martin, Jr.,* joined Crosstex Energy GP, LLC as a director in January 2006. He has been an independent residential and commercial real estate investor since 1991. From 1973 to 1991 he served as chairman of the public accounting firm Martin, Dolan and Holton in Richmond, Virginia. He began his career as an auditor at Ernst and Ernst. He holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant. Mr. Martin also serves on the board and as chairman of the audit committee for Comstock Resources, Inc. (NYSE:CRK), a growing independent energy company engaged in oil and gas acquisitions, exploration and development. Mr. Martin also has served as a director of Crosstex Energy, Inc. since January 2006.

*Kyle D. Vann* joined Crosstex Energy GP, LLC as a director in April 2006. Mr. Vann began his career with Exxon Corporation in 1969. After ten years at Exxon, he joined Koch Industries and served in various leadership capacities, including senior vice president from 1995 to 2000. In 2001, he then took on the role of CEO with Entergy-Koch, LP, a profitable energy trading and transportation company, which was sold in 2004. Currently, Mr. Vann, who is retired, continues to consult with Entergy and Texon, L.P. He also serves on the boards of Texon, L.P. and Legacy Reserves, LLC. Mr. Vann graduated from the University of Kansas with a Bachelor of Science degree in chemical engineering. He is a member of the Board of Advisors for the University of Kansas School of Engineering. Mr. Vann also serves on the board of various charitable organizations.

**Independent Directors**

Messrs. Best, Echols, Lubar, Martin, and Vann qualify as "independent" directors in accordance with the published listing requirements of The NASDAQ Stock Market (NASDAQ). The NASDAQ independence definition includes a series of objective tests, such as that the director is not an employee of the company and has not engaged in various types of business dealings with the company. In addition, as further required by the NASDAQ rules, the board of directors has made a subjective determination as to each independent director that no relationships exist which, in the opinion of the board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director.

In addition, the members of the Audit Committee also each qualify as "independent" under special standards established by the SEC for members of audit committees, and the Audit Committee includes at least one member who is determined by the board of directors to meet the qualifications of an "audit committee financial expert" in accordance with SEC rules, including that the person meets the relevant definition of an "independent" director. Messrs. Echols and Martin are both independent directors who have been determined to be audit committee financial experts. Unitholders should understand that this designation is a disclosure requirement of the SEC related to experience and understanding with respect to certain accounting and auditing matters. The designation does not impose any duties, obligations or liability that are greater than are generally imposed on a member of the Audit Committee and board of directors, and the designation of a director as an audit committee financial expert pursuant to this SEC requirement does not affect the duties, obligations or liability of any other member of the Audit Committee or board of directors.

**Board Committees**

The board of directors of Crosstex Energy GP, LLC, has, and appoints the members of, standing Audit, Compensation, Governance and Conflicts Committees. Each member of the Audit, Compensation, Governance and Conflicts Committees is an independent director in accordance with NASDAQ standards described above. Each of the board committees has a written charter approved by the board. Copies of the charters will be provided to any person, without charge, upon request. Contact Denise LeFevre at 214-721-9245 to request a copy of a charter or send your request to Crosstex Energy, L.P., Attn: Denise LeFevre, 2501 Cedar Springs, Dallas, Texas 75201.

The Audit Committee, comprised of Messrs. Echols (chair), Martin and Vann, assists the board of directors in its general oversight of our financial reporting, internal controls and audit functions, and is directly responsible for the appointment, retention, compensation and oversight of the work of our independent auditors.

The Conflicts Committee, comprised of Messrs. Vann (chair) and Best, reviews specific matters that the board believes may involve conflicts of interest between our general partner and Crosstex Energy, L.P. The Conflicts Committee determines if the resolution of a conflict of interest is fair and reasonable to us. The members of the Conflicts Committee are not officers or employees of our general partner or directors, officers or employees of its affiliates. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

The Compensation Committee, comprised of Messrs. Martin (chair) and Best, oversees compensation decisions for the officers of the General Partner as well as the compensation plans described herein.

The Governance Committee, comprised of Mr. Lubar (chair), reviews matters involving governance including assessing the effectiveness of current policies, monitoring industry developments, developing director selection criteria, recommending director nominees, recommending committee structures within the Board, managing the assessment process of the Board and individual directors, annually reviewing and recommending the compensation of directors and performing other duties as delegated from time to time.

**Code of Ethics**

Crosstex Energy GP, LLC, has adopted a Code of Business Conduct and Ethics applicable to all of our employees, officers and directors with regard to Partnership-related activities. The Code of Business Conduct and Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. A copy of our Code of Business Conduct and Ethics will be provided to any person, without charge, upon request. Contact Denise LeFevre at 214-721-9245 to request a copy of the Code or send your request to Crosstex Energy, L.P., Attn: Denise LeFevre, 2501 Cedar Springs, Dallas, Texas 75201. If any substantive amendments are made to the Code of Business Conduct and Ethics or if we or Crosstex Energy GP, LLC grant any waiver, including any implicit waiver, from a provision of the Code to any of our general partner's executive officers and directors, we will disclose the nature of such amendment or waiver in a report on Form 8-K.

**Section 16(a) — Beneficial Ownership Reporting Compliance**

Based on our records, except as set forth below, we believe that during 2008 all reporting persons complied with the Section 16(a) filing requirements applicable to them. Due to administrative errors, Form 4s reporting withholding of units by Crosstex Energy, L.P. to cover tax obligations on the vesting of restricted units were filed late on behalf of Barry E. Davis, William W. Davis, Jack M. Lafield, Robert S. Purgason and Susan J. McAden on January 29, 2008; a Form 3 was filed late on behalf of Leldon E. Echols on January 30, 2008; Form 4s reporting grants of restricted units were filed late on behalf of Rhys J. Best, Kyle D. Vann, James C. Crain, Leldon E. Echols, Cecil E. Martin Jr., and Sheldon B. Lubar on July 25, 2008; Form 4s reporting the lapse of restricted units upon leaving the Crosstex Energy GP, LLC Board of Directors were filed late on behalf of Robert F. Murchison and James C. Crain on October 16, 2008; and a Form 4 reporting the withholding of units by Crosstex Energy, L.P. to cover tax obligations on the vesting of restricted units was filed late on behalf of Joe A. Davis on November 12, 2008.

**Reimbursement of Expenses of our General Partner and its Affiliates**

Our general partner does not receive any management fee or other compensation in connection with its management of Crosstex Energy, L.P. However, our general partner performs services for us and is reimbursed by us for all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

**Item 11.** ***Executive Compensation***

**Compensation Discussion and Analysis**

We do not directly employ any of the persons responsible for managing our business. Crosstex Energy GP, LLC, the general partner of our general partner, manages our operations and activities, and its board of directors and officers make decisions on our behalf. The compensation of the directors, officers and employees of Crosstex Energy GP, LLC is determined by the Compensation Committee of the board of directors of Crosstex Energy GP, LLC. Our named executive officers also serve as executive officers of Crosstex Energy, Inc. and the compensation of the named executive officers discussed below reflects total compensation for services to all Crosstex entities. We reimburse all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides

that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Crosstex Energy, Inc. currently pays a monthly fee to us to cover its portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Based on the information that we track regarding the amount of time spent by each of our named executive officers on business matters relating to Crosstex Energy, L.P., we estimate that such officers devoted the following percentage of their time to the business of Crosstex Energy, L.P. and to Crosstex Energy, Inc., respectively, for 2008:

| Executive Officer or Director | Percentage of Time Devoted to Business of Crosstex Energy, L.P. | Percentage of Time Devoted to Business of Crosstex Energy, Inc. |
|---|---|---|
| Barry E. Davis | 83% | 17% |
| Jack M. Lafield* | 100% | 0% |
| William W. Davis | 74% | 26% |
| Robert S. Purgason | 100% | 0% |
| Joe A. Davis | 88% | 12% |

* Mr. Lafield departed from his position as Executive Vice President-Corporate Development with Crosstex Energy GP, LLC effective January 16, 2009.

Crosstex Energy GP, LLC's Compensation Committee assists the board of directors in discharging its responsibilities relating to compensation of executive officers and has overall responsibility for approval, evaluation and oversight of all compensation plans, policies and programs of Crosstex Energy GP, LLC. Each member of the Crosstex Energy GP, LLC's Compensation Committee is an independent director in accordance with NASDAQ standards. The responsibilities of Crosstex Energy GP, LLC's Compensation Committee, as stated in its charter, include the following:

- reviewing and making recommendations to the board of directors, on at least an annual basis, with respect to general compensation policies of Crosstex Energy GP, LLC relating to all officers and other key executives;
- reviewing and making recommendations to the board of directors, on at least an annual basis, for the annual base salary, award of options, awards under incentive compensation and equity-based plans, employment agreements, severance agreements, and change in control agreements and any special or supplemental benefits for senior executives;
- reviewing and making recommendations to the board of directors with respect to goals and objectives relevant to the compensation of senior executives, evaluating the senior executives' performance in light of these goals and objectives and recommending compensation levels based on this evaluation; and
- reviewing and reassessing the adequacy of the Compensation Committee's charter, on at least an annual basis, and recommending any proposed changes to the board of directors.

*Compensation Philosophy and Policies.* The primary objectives of Crosstex Energy GP, LLC's compensation program, including compensation of the named executive officers, are to attract and retain highly qualified officers, employees and directors and to reward individual contributions to our success. Crosstex Energy GP, LLC considers the following policies in determining the compensation of the named executive officers:

- total compensation is related to performance of the individual executive and the performance of the executive's division/executive team (measured against both financial and non-financial goals);
- incentive compensation represents a significant portion of the executive's total compensation;
- compensation levels are designed to be competitive to ensure that we will be able to attract and motivate highly qualified executive officers;
- payments under retention plans are designed to retain highly qualified officers during challenging times;
- incentive compensation balances long and short-term performance achievement; and
- compensation is related to improving unitholder value.

*Compensation Methodology.* The elements of Crosstex Energy GP, LLC's compensation program for named executive officers are intended to provide a total incentive package designed to drive performance and reward contributions in support of business strategies at the entity and individual performance. All compensation determinations are discretionary and, as noted above, subject to the decision-making authority of Crosstex Energy GP, LLC.

*Compensation Consultant*. In 2008, Crosstex Energy GP, LLC's Compensation Committee retained Mercer Human Resource Consulting ("Mercer") as its independent compensation consultant to conduct a compensation study and advise the Compensation Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees of Crosstex Energy GP, LLC. Mercer provided a presentation to the Compensation Committee regarding the compensation programs of the Crosstex entities in February 2008.

With respect to compensation objectives and decisions regarding the named executive officers the Compensation Committee has reviewed market data with respect to peer companies provided by Mercer in determining relevant compensation levels and compensation program elements for our named executive officers, including establishing base salaries, for fiscal 2008. Mercer has provided guidance on current industry best practices to the Compensation Committee. The market data that we reviewed included the base salaries paid to executive officers in similar positions at our peer companies, as well as a comparison of the mix of total compensation (including base salary, bonus structure, bonus methodology and short and long-term compensation elements) paid to executive officers in similar positions at such companies. For 2008, our peer companies consisted of the following: Energy Transfer Partners, L.P., Enbridge Energy Partners, L.P., ONEOK Partners, L.P., Southern Union, Magellan Midstream Holdings, L.P., NuStar Energy, L.P., Copano Energy, LLC, Regency Energy Partners, L.P., MarkWest Energy Partners, L.P., Boardwalk Pipeline Partners, L.P., Atmos Energy Corporation, El Paso Corporation, Questar Corporation, Equitable Resources, Inc., Pioneer Natural Resources Company, Plains Exploration & Production Company, Cabot Oil & Gas Corporation, St. Mary Land & Exploration Company and Range Resources Corporation. We believe that this group of companies is representative of the industry in which we operate and the individual companies were chosen because of such companies' relative position in our industry, their relative size/market capitalization, the relative complexity of the business, similar organizational structure and the named executive officers' roles and responsibilities.

In addition, the Compensation Committee has reviewed various relevant compensation surveys with respect to determining compensation for the named executive officers. In determining the long-term incentive component of compensation of the senior executives of Crosstex Energy GP, LLC (including the named executive officers), the Compensation Committee considers the performance and relative equity holder return, the value of similar incentive awards to senior executives at comparable companies, awards made to the company's senior executives in past years and such other factors as the Compensation Committee deems relevant.

With respect to bonus amounts and stock awards paid to our chief executive officer, the bonus and incentive award amounts differ in value from awards made to our other named executive officers because the scope of our chief executive officer's responsibilities are broader than those of our other named executive officers. In addition, our Compensation Committee considers the bonus and stock awards paid to similar named executive officers by our peer companies, which awards are generally higher for chief executive officers at our peer companies than for other executive officers at our peer companies.

*Elements of Compensation.* The primary elements of Crosstex Energy GP, LLC's compensation program are a combination of annual cash and long-term equity-based compensation. For fiscal year 2008, the principal elements of compensation for the named executive officers were the following:

- base salary;
- annual cash bonus plan awards;
- long-term incentive plan awards; and
- retirement and health benefits.

*Base Salary*. Crosstex Energy GP, LLC's Compensation Committee establishes base salaries for the named executive officers based on the historical salaries for services rendered to Crosstex Energy GP, LLC and its

affiliates, market data and responsibilities of the named executive officers. Salaries are generally determined by considering the employee's performance and prevailing levels of compensation in areas in which a particular employee works. As discussed above, except with respect to the monthly reimbursement payment received from Crosstex Energy, Inc., all of the base salaries of the named executive officers were allocated to us by Crosstex Energy GP, LLC as general and administration expenses. The base salaries paid to our named executive officers during fiscal year 2008 are shown in the Summary Compensation Table on page 85.

Each of the named executive officers, including Barry E. Davis, Jack M. Lafield, William W. Davis, Robert S. Purgason and Joe A. Davis have entered into employment agreements with Crosstex Energy GP, LLC. Mr. Lafield's employment agreement was replaced with a separation agreement with his departure on January 16, 2009. All of these employment agreements are substantially similar, with certain exceptions as set forth below. Each of the employment agreements has a term of one year that will automatically be extended such that the remaining term of the agreements will not be less than one year. The employment agreements provide for a base annual salary of $435,000, $315,000, $300,000 and $285,000 for Barry E. Davis, William W. Davis, Robert S. Purgason and Joe A. Davis, respectively, as of January 1, 2009.

The employment agreements also provide for a noncompetition period that will continue until the later of one year after the termination of the employee's employment or the date on which the employee is no longer entitled to receive payments under the employment agreement. During the noncompetition period, the employees are generally prohibited from engaging in any business that competes with us or our affiliates in areas in which we conduct business as of the date of termination and from soliciting or inducing any of our employees to terminate their employment with us.

*Annual Cash Bonus Plan Awards.* Crosstex Energy GP, LLC's Compensation Committee awarded cash bonus awards to each of the named executive officers in 2008. Crosstex uses financial and operational goals, as well as individual performance goals, to determine the amount of cash bonus awards that we pay to our named executive officers. Bonuses have been generally based on return on invested capital ("ROI"), bottom-line profitability, customer satisfaction, overall company growth, corporate governance, adherence to policies and procedures and other factors that vary depending on an employee's responsibilities. The calculation of ROI is reviewed by the Board and includes adjustments for capital expenditures that are not yet deployed in income producing activities and other similar matters. With certain exceptions, approximately two-thirds of the bonuses payable to our named executive officers for fiscal 2008 were based upon a formula that is tied to ROI achieved by us during the year. If a predetermined ROI is accomplished, then the bonus is paid and is increased or decreased based on the ROI percentage that is achieved, with minimum payouts of 10%, target payouts ranging from 65% to 100%, and maximum payouts ranging from 130% to 200% of an executive officer's base salary. Target ROI is based upon a standard of reasonable market expectations and company performance, and varies from year to year. Several factors are reviewed in determining target ROI, including market expectations, internal forecasts and available investment opportunities. For 2008, our ROI targets for bonuses were 9% for minimum bonuses, 11% for mid-point bonuses and 13% for maximum bonuses. We slightly exceeded the minimum ROI threshold of 9% with an ROI of 9.2% for 2008.

The remaining amount of the bonuses payable to our named executive officers for fiscal 2008 were determined in the discretion of the Compensation Committee, based upon the Compensation Committee's assessment of performance objectives. These performance objectives include the quality of leadership within the named executive officer's assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer and the named executive officer's contribution to, and enhancement of, the desired company culture. These performance objectives are reviewed and evaluated by our Compensation Committee as a whole. All of our named executive officers met or exceeded their personal performance objectives for 2008.

For 2009, the Board has approved a modification to the Annual Cash Bonus Plan to substitute earnings before interest, income taxes, depreciation and amortization, or EBITDA, as the performance metric in place of ROI. Under the revised 2009 plan, bonuses will be determined based on EBITDA levels ranging from a threshold of $195.0 million to a maximum of $280.0 million, with a mid-point EBITDA of $225.0 million. Payout of any such bonuses will be contingent on the Partnership's compliance with all long term debt covenants. The discretionary

portion of the bonus will operate in the same manner as in 2008. In addition, the Board has approved a Key Employee Retention Plan for 2009 that will include each of the named executive officers and certain other members of senior management. Under the plan, participants will receive retention payments in quarterly installments equal to 20% of base salary for the first three quarters of the year and 40% of base salary for the fourth quarter, provided that the participant is employed by the Partnership at the time of payment. In the case of a participant who is terminated by Crosstex without cause, such participant will receive a prorated payment based on time of employment. Payments made under this plan will be in lieu of payments that would otherwise be payable to a participant under the Annual Cash Bonus Plan up to the mid-point EBITDA of $225.0 million. The Key Employee Retention Plan is designed to retain and compensate certain key employees that are very important for the accomplishment of the Partnership's objectives during critical times. Participation in the plan is at the discretion of the Compensation Committee and the Board.

*Long-Term Incentive Plans.* We compensate our employees and directors with grants from long-term incentive plans adopted by each of Crosstex Energy GP, LLC and Crosstex Energy, Inc. A discussion of each plan follows:

*Crosstex Energy GP, LLC Long-Term Incentive Plan.* Crosstex Energy GP, LLC has adopted a long-term incentive plan for employees and directors of Crosstex Energy GP, LLC and its affiliates who perform services for us. The long-term incentive plan is administered by Crosstex Energy GP, LLC's Compensation Committee and permits the grant of awards covering an aggregate of 4,800,000 common units, which may be awarded in the form of restricted units or unit options. Of the 4,800,000 common units that may be awarded under the long-term incentive plan, 1,915,696 common units remain eligible for future grants by Crosstex Energy GP, LLC as of January 1, 2009. The long-term compensation structure is intended to align the employee's performance with long-term performance for our unitholders.

Crosstex Energy GP, LLC's board of directors in its discretion may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made. Crosstex Energy GP, LLC's board of directors also has the right to alter or amend the long-term incentive plan or any part of the plan from time to time, including increasing the number of units that may be granted subject to the approval requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

- *Unit Options.* The long-term incentive plan currently permits the grant of options covering common units. Under current policy all unit option grants will have an exercise price equal to or more than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the Compensation Committee. In addition, the unit options will become exercisable upon a change in control of us or our general partner, as discussed below under "— Potential Payments Upon a Change of Control or Termination." Upon exercise of a unit option, Crosstex Energy GP, LLC will acquire common units in the open market or directly from us or any other person or use common units already owned, or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the difference between the cost incurred by it in acquiring these common units and the proceeds received by it from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and Crosstex Energy GP, LLC will pay us the proceeds it received from the optionee upon exercise of the unit option. The unit option plan has been designed to furnish additional compensation to employees and directors and to align their economic interests with those of common unitholders.
- *Restricted Units.* A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. In the future, the Compensation Committee may make grants under the plan to employees and directors containing such terms as it shall determine under the plan. The Compensation Committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted units will vest upon a change of control of us or of our general partner, as discussed below under "— Potential Payments Upon a Change of Control or Termination." Common units to be

delivered upon the vesting of restricted units may be common units acquired by Crosstex Energy GP, LLC in the open market, common units already owned by Crosstex Energy GP, LLC, common units acquired by Crosstex Energy GP, LLC directly from us or any other person or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units which entitles the grantee to distributions attributable to the restricted units prior to vesting of such units. We intend the issuance of the common units upon vesting of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under current policy, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

- *Performance Units.* A performance unit represents a contractual commitment to grant restricted units in the future if certain conditions are satisfied. It is contemplated that performance unit agreements will only be entered into with members of our senior management. Under the terms of the performance unit agreements, to be eligible to receive the restricted units, the executive officer must continuously be employed from the date of the agreement through January 1 of the third calendar year following such date, and no units will be credited to an award recipient under our long term incentive plan until such future date. Each agreement provides for a target number of units that are to be granted in the future. The target number of units will be increased (up to a maximum of 200% of the target number of units for performance units granted in 2007 and up to a maximum of 300% for performance units granted in 2008) or decreased (to a minimum of 30% of the target number of units) based on Crosstex Energy, L.P.'s average growth rate (defined as the percentage increase or decrease in distributable cash flow per unit) compared to the target growth rate established in the applicable performance unit agreement which will vary from year to year. In 2007 and 2008 the target growth rate was 10.5%, and 9.0%, respectively. Generally, the restricted units that are granted pursuant to a performance unit agreement will vest and become unrestricted as of March 1 of the year of vesting if the executive officer remains an employee through such date.

On an aggregate basis, in the past the Crosstex entities generally have granted equity compensation in a amount of up to 300% of the chief executive officer's base salary and up to 200% of each other named executive officer's base salary. The total value of the equity compensation granted to our named executive officers generally has been allocated 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. For fiscal year 2008, Crosstex Energy GP, LLC granted 61,985, 28,499, 29,924, 28,499 and 27,074 performance units at target to Barry E. Davis, Jack M. Lafield, William W. Davis, Robert S. Purgason and Joe A. Davis, respectively. All performance and restricted units that we grant are charged against earnings according to SFAS No. 123R.

*Crosstex Energy, Inc. Long-Term Incentive Plan.* The objectives of Crosstex Energy, Inc.'s long-term incentive plan are to attract able persons to enter the employ of the company, to encourage employees to remain in the employ of the company, to provide motivation to employees to put forth maximum efforts toward the continued growth, profitability and success of the company by providing incentives to such persons through the ownership and/or performance of Crosstex Energy, Inc.'s common stock and to attract able persons to become directors of the company and to provide such individuals with incentive and reward opportunities. Awards to participants under the long-term incentive plan may be made in the form of stock options or restricted stock awards.

The Crosstex Energy, Inc. long-term incentive plan provides for the award of stock options and restricted stock (collectively, "Awards") for up to 4,590,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2009, approximately 626,453 shares remained available under the long-term incentive plan for future issuance to participants. A participant may not receive in any calendar year options relating to more than 100,000 shares of common stock. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Shares of common stock underlying Awards that are forfeited, terminated or expire unexercised become immediately available for additional Awards under the long-term incentive plan.

The Compensation Committee of Crosstex Energy, Inc.'s board of directors administers the long-term incentive plan. The administrator has the power to determine the terms of the options or other awards granted, including the exercise price of the options or other awards, the number of shares subject to each option or other award, the exercisability thereof and the form of consideration payable upon exercise. In addition, the administrator has the authority to grant waivers of long-term incentive plan terms, conditions, restrictions and limitations, and to amend, suspend or terminate the plan, provided that no such action may affect any share of common stock previously issued and sold or any option previously granted under the plan without the consent of the holder. Awards may be granted to employees, consultants and outside directors of Crosstex Energy, Inc.

The Compensation Committee of Crosstex Energy, Inc. will determine the type or types of Awards made under the plan and will designate the individuals who are to be the recipients of Awards. Each Award may be embodied in an agreement containing such terms, conditions and limitations as determined by the Compensation Committee of Crosstex Energy, Inc. Awards may be granted singly or in combination. Awards to participants may also be made in combination with, in replacement of, or as alternatives to, grants or rights under the plan or any other employee benefit plan of the company. All or part of an Award may be subject to conditions established by the Compensation Committee of Crosstex Energy, Inc., including continuous service with the company.

- *Stock Options.* Stock options are rights to purchase a specified number of shares of common stock at a specified price. An option granted pursuant to the plan may consist of either an incentive stock option that complies with the requirements of section 422 of the Code, or a nonqualified stock option that does not comply with such requirements. Only employees may receive incentive stock options and such options must have an exercise price per share that is not less than 100% of the fair market value of the common stock underlying the option on the date of grant. Nonqualified stock options also must have an exercise price per share that is not less than the fair market value of the common stock underlying the option on the date of grant. The exercise price of an option must be paid in full at the time an option is exercised.
- *Restricted Stock Awards.* Stock awards consist of restricted shares of common stock of Crosstex Energy, Inc. The Compensation Committee of Crosstex Energy, Inc. will determine the terms, conditions and limitations applicable to any restricted stock awards. Rights to dividends or dividend equivalents may be extended to and made part of any stock award at the discretion of the Crosstex Energy, Inc. Compensation Committee. Restricted stock awards will have a vesting period established in the sole discretion of the Compensation Committee, provided that the Compensation Committee may provide for earlier vesting by reason of death, disability, retirement or otherwise.
- *Performance Shares.* A performance share represents a contractual commitment to grant restricted shares in the future if certain conditions are satisfied. It is contemplated that performance share agreements will only be entered into with members of our senior management. Under the terms of the performance share agreements, to be eligible to receive the restricted shares, the executive officer must continuously be employed from the date of the agreement through January 1 of the third calendar year following such date, and no shares will be credited to an award recipient under our long term incentive plan until such future date. Each agreement provides for a target number of shares that are to be granted in the future. The target number of shares will be increased (up to a maximum of 200% of the target number of shares for performance units granted in 2007 and up to a maximum of 300% for performance units granted in 2008) or decreased (to a minimum of 30% of the target number of shares) based on Crosstex Energy, L.P.'s average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit) compared to the target growth rate established in the applicable performance shares agreement which will vary from year to year. In 2007 and 2008, the target growth rate was 10.5% and 9%, respectively. Generally, the restricted shares that are granted pursuant to a performance share agreement will vest and become unrestricted as of March 1 of the year of vesting if the executive officer remains an employee through such date.

Crosstex Energy, Inc.'s board of directors may amend, modify, suspend or terminate the long-term incentive plan for the purpose of addressing any changes in legal requirements or for any other purpose permitted by law, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring stockholder approval under any

applicable legal requirements will be effective until such approval has been obtained. No incentive stock options may be granted after the tenth anniversary of the effective date of the plan.

In the event of any corporate transaction such as a merger, consolidation, reorganization, recapitalization, separation, stock dividend, stock split, reverse stock split, split up, spin-off or other distribution of stock or property of Crosstex Energy, Inc., the Crosstex Energy, Inc. board of directors shall substitute or adjust, as applicable: (i) the number of shares of common stock reserved under this plan and the number of shares of common stock available for issuance pursuant to specific types of Awards as described in the plan, (ii) the number of shares of common stock covered by outstanding Awards, (iii) the grant price or other price in respect of such Awards and (iv) the appropriate fair market value and other price determinations for such Awards, in order to reflect such transactions, provided that such adjustments shall only be such that are necessary to maintain the proportionate interest of the holders of Awards and preserve, without increasing, the value of such Awards.

As discussed above, on an aggregate basis, in the past the Crosstex entities generally have granted equity compensation in a amount of up to 300% of the chief executive officer's base salary and up to 200% of each other named executive officer's base salary. The total value of the equity compensation granted to our executive officers generally has been awarded 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2008, Crosstex Energy, Inc. granted 58,748, 27,011, 28,361, 27,011 and 25,660 performance shares at target to Barry E. Davis, Jack M. Lafield, William W. Davis, Robert S. Purgason and Joe A. Davis, respectively. All performance and restricted shares that we grant are charged against earnings according to SFAS No. 123R.

*Retirement and Health Benefits.* Crosstex Energy GP, LLC offers a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are generally eligible for the same programs on the same basis as other employees of Crosstex Energy GP, LLC. Crosstex Energy GP, LLC maintains a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax advantages basis. In 2008, Crosstex Energy GP, LLC matched 100% of every dollar contributed for contributions of up to 6% of salary (not to exceed the maximum amount permitted by law) made by eligible participants. The retirement benefits provided to the named executive officers were allocated to us as general and administration expenses. Our executive officers are also eligible to participate in any additional retirement and health benefits available to our other employees.

*Perquisites and Other Compensation.* Crosstex Energy GP, LLC generally does not pay for perquisites for any of the named executive officers, other than payment of dues, sales tax and related expenses for membership in an industry related private lunch club (totaling less than $2,500 per year per person).

*Compensation Mix.* Crosstex Energy GP, LLC's Compensation Committee determines the mix of compensation, both among short and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the named executive officers. We believe that the mix of base salary, cash bonus awards, awards under the long-term incentive plan, retirement and health benefits and perquisites and other compensation fit our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies that we require.

*Potential Payments Upon a Change of Control or Termination.*

*Employment Agreements.* Under the employment agreements with our executive officers, we may be required to pay certain amounts upon a change of control of us or our affiliates or upon the termination of the executive officer in certain circumstances. Except in the event of our becoming bankrupt or ceasing operations, termination for cause or termination by the employee other than for good reason, or if a change in control occurs during the term of an employee's employment and either party to the agreement terminates the employee's employment as a result thereof, the employment agreements entered into between Crosstex Energy GP, LLC and each of the named executive officers provide for continued salary payments, bonus and benefits following termination of employment for the remainder of the employment term under the agreement. The terms contained

in the employment agreements were established at the time we entered into such agreements with our named executive officers. These terms were determined based on past practice and our understanding of similar agreements utilized by public companies generally at the time we entered into such agreements. The determination of the reasonable consequences of a change of control is periodically reviewed by the Compensation Committee. For purposes of the employment agreements:

- "Cause" means that:
  - the employee has failed to perform the duties assigned to him and such failure has continued for 30 days following delivery by Crosstex Energy GP, LLC of written notice to the employee of such failure;
  - the employee has been convicted of a felony or misdemeanor involving moral turpitude;
  - the employee has engaged in acts or omissions against Crosstex Energy GP, LLC constituting dishonesty, breach of fiduciary obligation or intentional wrongdoing or misfeasance;
  - the employee has acted intentionally or in bad faith in a manner that results in a material detriment to the assets, business or prospects of Crosstex Energy GP, LLC; or
  - the employee has breached any obligation under the employment agreement.
- "Good reason" includes any of the following:
  - the assignment to employee of any duties materially inconsistent with the employee's position (including a materially adverse change in the employee's office, title and reporting requirements), authority, duty or responsibilities;
  - Crosstex Energy GP, LLC requiring the employee to be based at any office other than the offices in the greater Dallas, Texas area;
  - any termination by Crosstex Energy GP, LLC of the employee's employment other than as expressly permitted by the employment agreement; or
  - a breach or violation by Crosstex Energy GP, LLC of any material provision of the employment agreement, which breach or violation remains unremedied for more than 30 days after written notice thereof is given to Crosstex Energy GP, LLC by the employee.
  - No act or failure to act on Crosstex Energy GP, LLC's part shall be considered "good reason" unless the employee has given Crosstex Energy GP, LLC written notice of such act or failure to act within 30 days thereof and Crosstex Energy GP, LLC fails to remedy such act or failure to act within 30 days of its receipt of such notice.
- A "change in control" shall be deemed to have occurred if:
  - Crosstex Energy, Inc. and/or its affiliates, collectively, no longer directly or indirectly hold a controlling interest in Crosstex Energy GP, L.P. or Crosstex Energy GP, LLC and the named executive officer does not remain employed by Crosstex Energy GP, LLC upon the occurrence of such event (whether the employee's employment is terminated voluntarily or by Crosstex Energy GP, LLC);
  - the consummation of any transaction as a result of which any person (other than Yorktown Partners LLC, a Delaware limited liability company, or its affiliates including any funds under its management) becomes the "beneficial owner" (as defined in Rule 13d-3 under the Securities Exchange Act of 1934, as amended), directly or indirectly, of at least 50% of the total voting power represented by the outstanding voting securities of Crosstex Energy, Inc. at a time when Crosstex Energy, Inc. still beneficially owns 50% or more of the voting power of the outstanding equity interests of Crosstex Energy GP, L.P. or Crosstex Energy GP, LLC; or
  - Crosstex Energy GP, LLC has caused the sale of at least 50% of our assets.

If a termination of a named executive officer by Crosstex Energy GP, LLC other than for cause, a termination by a named executive officer for good reason or upon a change in control were to have occurred as of December 31, 2008, our named executive officers would have been entitled to the following:

- Barry E. Davis would have received $435,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $78,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;
- Robert S. Purgason would have received $300,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $45,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;
- Jack M. Lafield would have received $300,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $45,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;
- William W. Davis would have received $315,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $147,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement; and
- Joe A. Davis would have received $285,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $43,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement.

*Long-Term Incentive Plan.* With respect to the Long-Term Incentive Plans, the amounts to be received by our named executive officers in these circumstances will be automatically determined based on the number of unvested stock or unit awards or restricted stock or units held by a named executive officer at the time of a change in control. The terms of the Long-Term Incentive Plans were determined based on past practice and our understanding of similar plans utilized by public companies generally at the time we adopted such plans. The determination of the reasonable consequences of a change of control is periodically reviewed by the Compensation Committee.

*Crosstex Energy GP, LLC Long-Term Incentive Plan.* Under current policy, if a grantee's employment is terminated for any reason other than death or disability, depending on the particular terms of the agreement in question, a grantee's unit options and restricted units granted under the long-term incentive plan may automatically be forfeited unless, and to the extent, the Compensation Committee provides otherwise. With respect to performance units, however, in the case of a termination without cause or for good reason, the pro-rata portion of the number of units that have accrued to the date of termination will vest and become payable to the participant. A grantee's options, restricted units and performance units will generally vest in the event of death or disability. Upon a change in control of us or our general partner, all unit options, restricted units and performance units will automatically vest and become payable or exercisable, as the case may be, in full and any restricted periods or performance criteria shall terminate or be deemed to have been achieved at the maximum level. For purposes of the long-term incentive plan, a "change in control" means, and shall be deemed to have occurred if:

- the consummation of a merger or consolidation of Crosstex Energy GP, LLC with or into another entity or any other transaction if persons who were not holders of equity interests of Crosstex Energy GP, LLC immediately prior to such merger, consolidation or other transaction, 50% or more of the voting power of the outstanding equity interests of the continuing or surviving entity;

- the sale, transfer or other disposition of all or substantially all of Crosstex Energy GP, LLC's or our assets;
- a change in the composition of the board of directors as a result of which fewer than 50% of the incumbent directors are directors who either had been directors of Crosstex Energy GP, LLC on the date 12 months prior to the date of the event that may constitute a change in control (the "original directors") or were elected, or nominated for election, to the board of directors of Crosstex Energy GP, LLC with the affirmative votes of at least a majority of the aggregate of the original directors who were still in office at the time of the election or nomination and the directors whose election or nomination was previously so approved; or
- the consummation of any transaction as a result of which any person (other than Yorktown Partners LLC, a Delaware limited liability company, or its affiliates including any funds under its management) becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of Crosstex Energy, Inc. representing at least 50% of the total voting power represented by CEI's then outstanding voting securities at a time when Crosstex Energy, Inc. still beneficially owns more than 50% of securities of Crosstex Energy GP, LLC representing at least 50% of the total voting power represented by Crosstex Energy GP, LLC's then outstanding voting securities.

If a change in control were to have occurred as of December 31, 2008, unit options, restricted units and performance units held by the named executive officers would have automatically vested and become payable or exercisable, as follows:

- Barry E. Davis held 16,667 restricted units and 218,117 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Robert S. Purgason held 18,886 restricted units, 101,043 performance units and options to purchase 10,000 common units that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Jack M. Lafield held 10,145 restricted units and 101,043 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control; and
- William W. Davis held 10,145 restricted units and 105,318 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control.
- Joe A. Davis held 7,199 restricted units and 91,876 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control;

*Crosstex Energy, Inc. Long-Term Incentive Plan.* Under current policy, if a grantee's employment is terminated for any reason other than death or disability, depending on the particular terms of the agreement in question, a grantee's options and restricted shares that have been granted may automatically be forfeited unless, and to the extent, the Compensation Committee provides otherwise. With respect to performance shares, however, in the case of a termination without cause or for good reason, the pro-rata portion of the number of shares that have accrued to the date of termination will vest and become payable to the participant. A grantee's options, restricted shares and performance shares will generally vest in the event of death or disability. Immediately prior to a "change of control" of Crosstex Energy, Inc., all option awards, restricted stock awards and performance shares will automatically vest and become payable or exercisable, as the case may be, in full and all vesting periods will terminate. For purposes of the long-term incentive plan, a "change of control" means:

- the consummation of a merger or consolidation of Crosstex Energy, Inc. with or into another entity or any other transaction, if persons who were not shareholders of Crosstex Energy, Inc. immediately prior to such merger, consolidation or other transaction beneficially own immediately after such merger, consolidation or other transaction 50% or more of the voting power of the outstanding securities of each of (i) the continuing or surviving entity and (ii) any direct or indirect parent entity of such continuing or surviving entity;
- the sale, transfer or other disposition of all or substantially all of Crosstex Energy, Inc.'s assets;
- a change in the composition of the board of directors of Crosstex Energy, Inc. as a result of which fewer than 50% of the incumbent directors are directors who either (i) had been directors of Crosstex Energy, Inc. on the date 12 months prior to the date of the event that may constitute a change of control (the "original directors")

or (ii) were elected, or nominated for election, to the board of directors of Crosstex Energy, Inc. with the affirmative votes of at least a majority of the aggregate of the original directors who were still in office at the time of the election or nomination and the directors whose election or nomination was previously so approved; or

- any transaction as a result of which any person is the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of Crosstex Energy, Inc. representing at least 50% of the total voting power represented by Crosstex Energy, Inc.'s then outstanding voting securities.

If a change in control were to have occurred as of December 31, 2008, options and restricted stock held by the named executive officers would have automatically vested and become payable or exercisable, and any vesting periods of restricted stock would have terminated, as follows:

- Barry E. Davis held 38,154 shares of restricted stock and 213,744 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Robert S. Purgason held 38,631 shares of restricted stock, 98,985 performance shares and options to purchase 30,000 common shares that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Jack M. Lafield held 36,594 shares of restricted stock and 98,985 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control;
- William W. Davis 36,594 shares of restricted stock and 103,035 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control; and
- Joe A. Davis held 8,565 shares of restricted stock and 87,634 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control.

*Role of Executive Officers in Executive Compensation.* Crosstex Energy GP, LLC's Compensation Committee determines the compensation payable to each of the named executive officers. None of the named executive officers serves as a member of the Compensation Committee. However, our chief executive officer, Barry E. Davis, provides periodic recommendations to the Compensation Committee regarding the compensation of the other named executive officers.

*Tax and Accounting Considerations.* The equity compensation grant policies of the Crosstex entities have been impacted by the implementation of SFAS No. 123R, which we adopted effective January 1, 2006. Under this accounting pronouncement, we are required to value unvested unit options granted prior to our adoption of SFAS 123 under the fair value method and expense those amounts in the income statement over the stock option's remaining vesting period. As a result, the Crosstex entities currently intend to discontinue grants of unit option and stock option awards and instead grant restricted unit and restricted stock awards to the named executive officers and other employees. The Crosstex entities have structured the compensation program to comply with Internal Revenue Code Section 409A. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income. None of the named executive officers or other employees had non-performance based compensation paid in excess of the $1.0 million tax deduction limit contained in Internal Revenue Code Section 162(m).

**Summary Compensation Table**

The following table sets forth certain compensation information for our chief executive officer and our four other most highly compensated executive officers in 2008.

| Name and Principal Position | Year | Salary ($) | Bonus ($) | Stock Awards ($)(6) | Option Awards ($) | Non-Equity Incentive Plan Compensation ($) | Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) | All Other Compensation ($) | Total ($) |
|---|---|---|---|---|---|---|---|---|---|
| Barry E. Davis | 2008 | 435,000 | 78,000 | 1,154,104 | — | — | — | 356,580(1) | 2,023,684 |
| *President and Chief* | 2007 | 400,000 | 400,000 | 1,111,409 | — | — | — | 213,210(1) | 2,124,619 |
| *Executive Officer* | 2006 | 390,000 | 95,000 | 1,126,875 | — | — | — | 167,630(1) | 1,779,505 |
| Robert S. Purgason | 2008 | 300,000 | 45,000 | 530,627 | — | — | — | 224,589(2) | 1,100,216 |
| *Executive Vice* | 2007 | 290,000 | 226,000 | 534,691 | — | — | — | 175,038(2) | 1,225,729 |
| *President and Chief Operating Officer* | 2006 | 222,385 | 47,500 | 1,392,025 | — | — | — | 113,267(2) | 1,775,177 |
| Jack M. Lafield | 2008 | 300,000 | 45,000 | 530,627 | — | — | — | 211,951(3) | 1,087,578 |
| *Executive Vice* | 2007 | 290,000 | 226,000 | 534,691 | — | — | — | 222,622(3) | 1,273,313 |
| *President* | 2006 | 275,000 | 60,000 | 685,926 | — | — | — | 198,061(3) | 1,218,987 |
| William W. Davis | 2008 | 315,000 | 147,000 | 557,137 | — | — | — | 220,452(4) | 1,239,589 |
| *Executive Vice* | 2007 | 290,000 | 226,000 | 534,691 | — | — | — | 227,411(4) | 1,278,102 |
| *President and Chief Financial Officer* | 2006 | 275,000 | 60,000 | 685,926 | — | — | — | 198,061(4) | 1,218,987 |
| Joe A. Davis | 2008 | 285,000 | 43,000 | 504,085 | — | — | — | 234,324(5) | 1,066,409 |
| *Executive Vice* | 2007 | 265,000 | 226,000 | 366,422 | — | — | — | 137,440(5) | 994,862 |
| *President and General Counsel* | 2006 | 250,000 | 47,500 | 549,967 | — | — | — | 86,349(5) | 933,816 |

(1) Amount of all other compensation for Mr. Barry Davis includes distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $192,471 in 2008, $123,134 in 2007 and $95,251 in 2006, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $139,374 in 2008, $83,308 in 2007 and $62,755 in 2006.

(2) Amount of all other compensation for Mr. Purgason includes distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $112,788 in 2008, $66,202 in 2007 and $18,520 in 2006, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $87,873 in 2008, $64,097 in 2007 and $37,260 in 2006.

(3) Amount of all other compensation for Mr. Lafield includes distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $96,430 in 2008, $113,048 in 2007 and $97,211 in 2006, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $91,709 in 2008, $106,806 in 2007 and $93,438 in 2006.

(4) Amount of all other compensation for Mr. William Davis includes distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $98,923 in 2008, $113,048 in 2007 and $97,211 in 2006, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $93,140 in 2008, $106,806 in 2007 and $93,438 in 2006.

(5) Amount of all other compensation for Mr. Joe Davis includes distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $118,791 in 2008, $76,876 in 2007 and $47,925 in 2006, and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $91,625 in 2008, $52,988 in 2007 and $36,300 in 2006.

(6) The amounts shown represent the amount recognized for financial statement reporting purposes computed in accordance with Statement of Financial Accounting Standards No. 123R, "*Share-Based Payment."* See Note 11 to our audited financial statements included in Item 8 herein for the assumptions made in our valuation of such awards.

**Grants of Plan-Based Awards for Fiscal Year 2008 Table**

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2008, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plan.

**CROSSTEX ENERGY GP, LLC — GRANTS OF PLAN-BASED AWARDS**

| | | Estimated Future Payouts Under Equity Incentive Plan Awards | | | |
|---|---|---|---|---|---|
| Name | Grant Date | Threshold (#) | Target (#) | Maximum (#) | Grant Date Fair Value of Unit Awards ($)(1) |
| Barry E. Davis | 3/27/08 | 18,596 | 61,985 | 185,955 | 571,455 |
| Robert S. Purgason | 3/27/08 | 8,550 | 28,499 | 85,497 | 262,742 |
| Jack M. Lafield | 3/27/08 | 8,550 | 28,499 | 85,497 | 262,742 |
| William W. Davis | 3/27/08 | 8,977 | 29,924 | 89,772 | 275,863 |
| Joe A. Davis | 3/27/08 | 8,122 | 27,074 | 81,222 | 249,589 |

(1) Performance units reported at the threshold (minimum) number of units. Performance units awarded to named executive officers in 2008 included distribution rights for the target level units. See discussion of award characteristics on page 78.

**CROSSTEX ENERGY, INC. — GRANTS OF PLAN-BASED AWARDS**

| | | Estimated Future Payouts Under Equity Incentive Plan Awards | | | |
|---|---|---|---|---|---|
| Name | Grant Date | Threshold (#) | Target (#) | Maximum (#) | Grant Date Fair Value of Stock Awards ($)(1) |
| Barry E. Davis | 3/27/08 | 17,624 | 58,748 | 176,244 | 582,649 |
| Robert S. Purgason | 3/27/08 | 8,103 | 27,011 | 81,033 | 267,885 |
| Jack M. Lafield | 3/27/08 | 8,103 | 27,011 | 81,033 | 267,885 |
| William W. Davis | 3/27/08 | 8,508 | 28,361 | 85,083 | 281,274 |
| Joe A. Davis | 3/27/08 | 7,698 | 25,660 | 76,980 | 254,496 |

(1) Performance shares reported at the threshold (minimum) number of units. Performance shares awarded to named executive officers in 2008 included dividend rights for the target level shares. See discussion of award characteristics on page 79.

**Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2008**

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2008, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plan.

**CROSSTEX ENERGY GP, LLC — OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END**

| | Option Awards | | | | | Stock Awards | | | |
|---|---|---|---|---|---|---|---|---|---|
| Name | Number of Securities Underlying Unexercised Options (#) Exercisable | Number of Securities Underlying Unexercised Options (#)(3) Unexercisable | Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) | Option Exercise Price ($) | Option Expiration Date | Number of Units That Have Not Vested (#) | Market Value of Units That Have Not Vested ($)(1) | Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(2) | Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1) |
| Barry E. Davis | — | — | — | — | — | 16,667 | 72,835 | 4,824(4) | 21,081 |
| | | | | | | | | 18,596(5) | 81,265 |
| Robert S. Purgason | 5,000 | 5,000 | — | 30.00 | 11/15/14 | 18,886 | 82,532 | 2,331(4) | 10,186 |
| | | | | | | | | 8,550(5) | 37,364 |
| Jack M. Lafield | — | — | — | — | — | 10,145 | 44,334 | 2,331(4) | 10,186 |
| | | | | | | | | 8,550(5) | 37,364 |
| William W. Davis | — | — | — | — | — | 10,145 | 44,334 | 2,331(4) | 10,186 |
| | | | | | | | | 8,977(5) | 39,229 |
| Joe A. Davis | — | — | — | — | — | 7,199 | 31,460 | 1,598(4) | 6,983 |
| | | | | | | | | 8,122(5) | 35,493 |

(1) The closing price for the common units was $4.37 as of December 31, 2008.

(2) Performance units reported at the threshold (minimum) number of units. See discussion on page 78.

(3) Options vest and become exercisable on November 5, 2009.

(4) Performance units vest on March 1, 2010.

(5) Performance units vest on March 1, 2011.

**CROSSTEX ENERGY, INC. — OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END**

| | Option Awards | | | | | Stock Awards | | | |
|---|---|---|---|---|---|---|---|---|---|
| Name | Number of Securities Underlying Unexercised Options (#) Exercisable | Number of Securities Underlying Unexercised Options (#) Unexercisable | Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) | Option Exercise Price ($) | Option Expiration Date | Number of Shares or Units of Stock That Have Not Vested (#) | Market Value of Shares or Units of Stock That Have Not Vested ($)(1) | Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(2) | Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1) |
| Barry E. Davis | — | — | — | — | — | 38,154 | 148,801 | 5,625(3) | 24,581 |
| | | | | | | | | 17,624(4) | 77,017 |
| Robert S. Purgason | 15,000 | 15,000 | — | 13.33 | 12/07/14 | 38,631 | 150,661 | 2,692(3) | 11,764 |
| | | | | | | | | 8,103(4) | 35,410 |
| Jack M. Lafield | — | — | — | — | — | 36,594 | 142,717 | 2,692(3) | 11,764 |
| | | | | | | | | 8,103(4) | 35,410 |
| William W. Davis | — | — | — | — | — | 36,594 | 142,717 | 2,692(3) | 11,764 |
| | | | | | | | | 8,508(4) | 37,180 |
| Joe A. Davis | — | — | — | — | — | 8,565 | 33,404 | 1,845(3) | 8,063 |
| | | | | | | | | 7,698(4) | 33,640 |

(1) The closing price for the common stock was $3.90 as of December 31, 2008.

(2) Performance shares reported at the threshold (minimum) number of shares. See discussion on page 79.

(3) Performance shares vest on March 1, 2010.

(4) Performance shares vest on March 1, 2011.

**Option Exercises and Units and Shares Vested Table for Fiscal Year 2008**

The following table provides information related to the exercise of options and vesting of restricted units and restricted shares during fiscal year ended 2008.

**OPTION EXERCISES AND UNITS AND SHARES VESTED**

| | Crosstex Energy, L.P. Unit Awards | | Crosstex Energy, Inc. Share Awards | |
|---|---|---|---|---|
| Name | Number of Units Acquired on Vesting (#) | Value Realized on Vesting ($) | Number of Shares Acquired on Vesting (#) | Value Realized on Vesting ($) |
| Barry E. Davis | 23,857 | 757,424 | 37,500 | 1,370,325 |
| Robert S. Purgason | 4,286 | 132,952 | 9,999 | 372,363 |
| Jack M. Lafield | 32,714 | 1,025,848 | 71,250 | 2,614,088 |
| William W. Davis | 32,714 | 1,025,848 | 71,250 | 2,614,088 |
| Joe A. Davis | 22,500 | 328,725 | 45,000 | 781,177 |

**Compensation of Directors for Fiscal Year 2008**

**DIRECTOR COMPENSATION**

| Name | Fees Earned or Paid in Cash ($) | Unit Awards(1) ($) | All Other Compensation(2) ($) | Total ($) |
|---|---|---|---|---|
| Rhys J. Best | 154,333 | 74,991 | 9,699 | 239,023 |
| James C. Crain | 42,750 | — | 6,891 | 49,641 |
| Leldon E. Echols | 66,125 | 37,495 | 1,253 | 104,873 |
| Bryan H. Lawrence | — | — | — | — |
| Sheldon B. Lubar | 68,751 | 37,495 | 8,445 | 114,691 |
| Cecil E. Martin | 80,625 | 37,495 | 8,445 | 126,565 |
| Robert F. Murchison | 19,250 | — | 6,192 | 25,442 |
| Kyle D. Vann | 149,000 | 74,991 | 9,699 | 233,690 |

(1) Messrs. Best, Crain, Echols, Lubar, Martin and Vann were granted awards of restricted units of Crosstex Energy, L.P. on May 23, 2008 with a fair market value of $33.81 per unit and that will vest on May 7, 2009 in the following amounts, respectively: 2,218; 1,109; 1,109; 1,109; 1,109; and 2, 218. Mr. Crain forfeited his units when he resigned from the Board on August 13, 2008. The amounts shown represent the amount recognized for financial statement reporting purposes computed in accordance with Statement of Financial Accounting Standards No. 123R, "Share Based Payment." See Note 11 to our audited financial statements included in Item 8 herein for the assumptions made in our valuation of such awards. At December 31, 2008, Messrs. Best, Echols, Lubar, Martin and Vann held aggregate outstanding restricted unit awards, in the following amounts, respectively: 4,218; 1,109; 3,109; 3,109; and 4,218. Messrs. Crain and Lawrence held no outstanding restricted unit awards at December 31, 2008.

(2) Other Compensation is comprised of distributions on restricted units.

Each director of Crosstex Energy GP, LLC who is not an employee of Crosstex Energy GP, LLC (except Mr. Lawrence) is paid an annual retainer fee of $50,000. Directors do not receive an attendance fee for each

regularly scheduled quarterly board meeting, but are paid $1,500 for each additional meeting that they attend. Also, an attendance fee of $1,500 is paid to each director for each committee meeting he attends. Each committee chairman receives $2,500 annually, except the Audit Committee chairman who receives $7,500 annually. The Lead Director is paid a fee of $7,500 annually. Directors are also reimbursed for related out-of-pocket expenses. Barry E. Davis, as an executive officer of Crosstex Energy GP, LLC, is otherwise compensated for his services and therefore receives no separate compensation for his service as a director. For directors that serve on both the boards of Crosstex Energy GP, LLC and Crosstex Energy, Inc., the above listed fees are generally allocated 75% to us and 25% to Crosstex Energy, Inc. The Governance Committee annually reviews and makes recommendations to the Board of Directors regarding the compensation of the directors.

**Compensation Committee Interlocks and Insider Participation**

During the fiscal year ended 2008, the Compensation Committee was composed of Kyle Vann, Cecil E. Martin and Rhys J. Best. Mr. Murchison was also a member of the committee until his departure from the Board on May 7, 2008. No member of the Compensation Committee was an officer or employee of Crosstex Energy GP, LLC. None of Crosstex Energy GP, LLC's executive officers served on the board of directors or the compensation committee of any other entity, for which any officers of such other entity served either on Crosstex Energy GP, LLC's Board of Directors or Compensation Committee.

**Compensation Committee Report**

The Compensation Committee of Crosstex Energy GP, LLC held five meetings during fiscal year 2008. The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with management. Based upon such review, the related discussions and such other matters deemed relevant and appropriate by the Compensation Committee, the Compensation Committee has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Cecil E. Martin (Chairman)
Rhys J. Best

**Item 12.** ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters***

**Crosstex Energy, L.P. Ownership**

The following table shows the beneficial ownership of units of Crosstex Energy, L.P. as of February 16, 2009, held by:

- each person who beneficially owns 5% or more of any class of units then outstanding;
- all the directors of Crosstex Energy GP, LLC;
- each named executive officer of Crosstex Energy GP, LLC; and
- all the directors and executive officers of Crosstex Energy GP, LLC as a group.

Percentages reflected in the table are based upon a total of 44,958,955 common units and 3,875,340 senior subordinated series D units as of February 16, 2009.

| Name of Beneficial Owner(1) | Common Units Beneficially Owned | Percentage of Common Units Beneficially Owned | Subordinated Series D Units Beneficially Owned | Percentage of Subordinated Series D Units Beneficially Owned | Total Units Beneficially Owned | Percentage of Total Units Beneficially Owned |
|---|---|---|---|---|---|---|
| Crosstex Energy, Inc. | 16,414,830 | 36.51% | | | 16,414,830 | 33.62% |
| Kayne Anderson Capital Advisors, LP(2) | 6,044,069 | 13.44% | | | 6,044,069 | 12.38% |
| Tortoise Capital Advisors, LLC(3) | 2,594,681 | 5.77% | 775,068 | 20.00% | 3,369,749 | 6.90% |
| Chieftain Capital Management, Inc.(4) | 3,112,076 | 6.92% | | | 3,112,076 | 6.37% |
| Lehman Brothers MLP Opportunity Fund L.P | 0 | * | 968,835 | 25.00% | 968,835 | 1.98% |
| Fiduciary/Claymore MLP Opportunity Fund | 0 | * | 387,534 | 10.00% | 387,534 | * |
| ING Life Insurance & Annuity Company(5) | 0 | * | 705,312 | 18.20% | 705,312 | 1.44% |
| Citigroup Global Markets Inc. | 0 | * | 775,068 | 20.00% | 775,068 | 1.59% |
| Barry E. Davis(6) | 65,716 | * | | | 65,716 | * |
| William W. Davis(6) | 28,975 | * | | | 28,975 | * |
| Robert S. Purgason(6) | 16,853 | * | | | 16,853 | * |
| Joe A. Davis(6) | 17,548 | * | | | 17,548 | * |
| Rhys J. Best | 17,010 | * | | | 17,010 | * |
| Leldon E. Echols | 0 | * | | | 0 | * |
| Bryan H. Lawrence(6) | 0 | * | | | 0 | * |
| Sheldon B. Lubar(6)(7) | 316,932 | * | | | 316,932 | * |
| Cecil E. Martin | 17,010 | * | | | 17,010 | * |
| Kyle D. Vann | 11,010 | * | | | 11,010 | * |
| All directors and executive officers as a group (10 persons) | 491,054 | 1.10% | 0 | 0.00% | 491,054 | 1.00% |

* Less than 1%

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022; Chieftain Capital Management, FAC, which is 12 East 49th Street, New York, New York 10017; Kayne Anderson Capital Advisors, L.P., which is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067; Tortoise Capital Advisors LLC, which 11550 Ash Street, Suite 300, Leawood, Kansas 66211; Lehman Brothers MLP Opportunity Fund L.P., which is 745 7th Avenue, New York, New York 10019; Fiduciary/Claymore MLP Opportunity Fund which is 8112 Maryland Avenue, Ste 400, St. Louis, Missouri 63105; ING Life Insurance & Annuity Company which is 5780 Powers Ferry Road NW, Ste 300, Atlanta, Georgia 30327-4349; and Citigroup Global Markets Inc. which is 390 Greenwich Street, 3rd Floor, New York, New York 10013.

(2) As reported on Schedule 13G filed with the SEC in a joint filing with Richard A. Kayne.

(3) As reported on Schedule 13G filed with the SEC in a joint filing with Tortoise Energy Capital Corporation.

(4) As reported on Schedule 13G filed with the SEC.

(5) Reported jointly with ING USA Annuity and Life Insurance Company.

(6) These individuals each hold an ownership interest in Crosstex Energy, Inc. as indicated in the following table.

(7) Sheldon B. Lubar is a general partner of Lubar Nominees, which holds an ownership interest in Crosstex Energy, Inc. (as indicated in the following table). Mr. Lubar is also a director of the manager of Lubar Equity Fund, LLC, which holds an ownership interest in Crosstex Energy, Inc. (as indicated in the following table) and owns 285,100 Common Units of Crosstex Energy, L.P.

**Crosstex Energy, Inc. Ownership**

The following table shows the beneficial ownership of Crosstex Energy, Inc. as of February 16, 2009, held by:

- each person who beneficially owns 5% or more of the stock then outstanding;
- all the directors of Crosstex Energy Inc.;
- each named executive officer of Crosstex Energy Inc.; and
- all the directors and executive officers of Crosstex Energy Inc. as a group.

Percentages reflected in the table below are based on a total of 46,472,805 shares of common stock outstanding as of February 16, 2009.

| Name of Beneficial Owner(1) | Shares of Common Stock | Percent |
|---|---|---|
| Chieftain Capital Management, Inc.(2) | 6,485,903 | 13.96% |
| ClearBridge Advisors, LLC(2) | 3,016,018 | 6.49% |
| Barclays Global Investors, NA(3) | 5,089,146 | 10.95% |
| Lubar Nominees(4) | 1,991,877 | 4.29% |
| Lubar Equity Fund, LLC(4) | 468,210 | 1.01% |
| Barry E. Davis | 1,337,745 | 2.88% |
| William W. Davis | 168,819 | * |
| Robert S. Purgason(5) | 31,357 | * |
| Joe A. Davis | 30,757 | * |
| James C. Crain(6) | 6,000 | * |
| Leldon E. Echols | 0 | * |
| Bryan H. Lawrence | 1,720,267 | 3.70% |
| Sheldon B. Lubar(4) | 15,000 | * |
| Cecil E. Martin | 0 | * |
| Robert F. Murchison(7) | 227,395 | * |
| All directors and executive officers as group (10 persons) | 5,997,427 | 12.91% |

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Chieftain Capital Management, Inc., which is 12 East 49th Street, New York, New York 10017; Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022; ClearBridge Advisors, LLC which is 620 8th Avenue, New York, New York 10018; Barclays Global Investors, NA which is 45 Fremont Street, San Francisco, California 94105; and Alson Capital Partners, LLC which is 810 7th Avenue, 39th Floor, New York, New York 10019.

(2) As reported on Schedule 13G filed with the SEC.

(3) As reported on Schedule 13G filed with the SEC in a joint filing with Barclays Global Fund Advisors and Barclays Global Investors Japan Limited.

(4) As reported on Schedule 13D filed with the SEC. Sheldon B. Lubar is a general partner of Lubar Nominees and director of the manager of Lubar Equity Fund, LLC, and may be deemed to beneficially own the shares held by these entities.

(5) 600 of these shares are held by the M. I. Purgason Trust, of which Mr. Purgason serves as co-trustee.

(6) 1,000 of these shares are held by the James C. Crain Trust.

(7) 169,462 shares are held by Murchison Capital Partners, L.P. Mr. Murchison is the President of the Murchison Management Corp., which serves as the general partner of Murchison Capital Partners, L.P.

**Beneficial Ownership of General Partner Interest**

Crosstex Energy GP, L.P. owns all of our 2% general partner interest and all of our incentive distribution rights. Crosstex Energy GP, L.P. is owned 0.001% by its general partner, Crosstex Energy GP, LLC and 99.999% by Crosstex Energy, Inc.

**Item 13.** ***Certain Relationships and Related Transactions and Director Independence***

**Our General Partner**

Our operations and activities are managed by, and our officers are employed by, the Operating Partnership. Our general partner does not receive any management fee or other compensation in connection with its management of our business, but it is reimbursed for all direct and indirect expenses incurred on our behalf.

Our general partner owns a 2% general partner interest in us and all of our incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit.

**Relationship with Crosstex Energy, Inc.**

*General.* CEI owns 16,414,830 common units, representing approximately 34% limited partnership interest in us. Our general partner owns a 2% general partner interest in us and the incentive distribution rights. Our general partner's ability, as general partner, to manage and operate Crosstex Energy, L.P. and Crosstex Energy, Inc.'s ownership in us effectively gives our general partner the ability to veto some of our actions and to control our management. Crosstex Energy, Inc. pays us for administrative and compensation costs that we incur on its behalf. During 2008, this fee was approximately $0.06 million per month.

*Omnibus Agreement.* Concurrent with the closing of our initial public offering, we entered into an agreement with CEI, Crosstex Energy GP, LLC and our general partner that governs potential competition among us and the other parties to the agreement. Crosstex Energy, Inc. agreed, for so long as our general partner or any affiliate of CEI is a general partner of our Partnership, not to engage in the business of gathering, transmitting, treating, processing, storing and marketing of natural gas and the transportation, fractionation, storing and marketing of NGLs unless it first offers us the opportunity to engage in this activity or acquire this business, and the board of directors of Crosstex Energy GP, LLC, with the concurrence of its conflicts committee, elects to cause us not to pursue such opportunity or acquisition. In addition, CEI has the ability to purchase a business that has a competing natural gas gathering, transmitting, treating, processing and producer services business if the competing business does not represent the majority in value of the business to be acquired and CEI offers us the opportunity to purchase the competing operations following their acquisition. Except as provided above, CEI and its controlled affiliates are not prohibited from engaging in activities in which they compete directly with us.

**Related Party Transactions**

*Crosstex Denton County Gathering J.V.* We own a majority interest, before application of any dilution rights, in Crosstex Denton County Gathering, J.V. (CDC). CDC was formed to build, own and operate a natural gas gathering system in Denton County, Texas. We manage the business affairs of CDC. The other joint venture partner (the CDC Partner) is an unrelated third party who owns and operates the natural gas field located in Denton County. In connection with the formation of CDC, we agreed to loan the CDC Partner up to $1.5 million for their initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to us attributable to CDC Partner's share of distributable cash flow to repay the loan which has a balance remaining of $0.4 million.

*Reimbursement of Costs by CEI.* CEI paid us, $0.7 million, $0.6 million and $0.5 million during the years ended December 31, 2008, 2007, and 2006, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI.

*Approval and Review of Related Party Transactions.* If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of Crosstex Energy GP, LLC or our senior management, as appropriate. If the board of directors is involved in the approval process, it determines whether it is advisable to refer the matter to the Conflicts Committee, as constituted under the limited partnership agreement of Crosstex Energy, L.P. If a matter is referred to the Conflicts Committee, the Conflicts Committee obtains information regarding the proposed transaction from management and determines whether it is advisable to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the committee retains such counsel or financial advisor, it considers the advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

**Item 14.** ***Principal Accounting Fees and Services***

**Audit Fees**

The fees for professional services rendered for the audit of our annual financial statements for each of the fiscal years ended December 31, 2008 and December 31, 2007, review of our internal control procedures for the fiscal year ended December 31, 2008 and December 31, 2007, and the reviews of the financial statements included in our Quarterly Reports on Forms 10-Q or services that are normally provided by KPMG in connection with statutory or regulatory filings or engagements for each of those fiscal years were $1.2 million. These amounts also included fees associated with comfort letters and consents related to debt and equity offerings.

**Audit-Related Fees**

KPMG did not perform any assurance and related services related to the performance of the audit or review of our financial statements for the fiscal years ended December 31, 2008 and December 31, 2007 that were not included in the audit fees listed above.

**Tax Fees**

We did not incur any fees by KPMG for tax compliance, tax advice and tax planning for the years ended December 31, 2008 and December 31, 2007.

**All Other Fees**

KPMG did not render services to us, other than those services covered in the section captioned "Audit Fees" for the fiscal years ended December 31, 2008 and December 31, 2007.

**Audit Committee Approval of Audit and Non-Audit Services**

All audit and non-audit services and any services that exceed the annual limits set forth in the policy must be pre-approved by the Audit Committee. In 2009, the Audit Committee has not pre-approved the use of KPMG for any non-audit related services. The Chairman of the Audit Committee is authorized by the Audit Committee to pre-approve additional KPMG audit and non-audit services between Audit Committee meetings; provided that the additional services do not affect KPMG's independence under applicable Securities and Exchange Commission rules and any such pre-approval is reported to the Audit Committee at its next meeting.

**PART IV**

**Item 15.** ***Exhibits and Financial Statement Schedules***

(a) Financial Statements and Schedules

(1) See the Index to Financial Statements on page F-1.

(2) See Schedule II — Valuation and Qualifying Accounts on Page F-47.

(3) Exhibits

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

| Number | | Description |
|---|---|---|
| 3.1 | — | Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779). |
| 3.2 | — | Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007). |
| 3.3 | — | Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007). |
| 3.4 | — | Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008). |
| 3.5 | — | Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779). |
| 3.6 | — | Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004). |
| 3.7 | — | Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779). |
| 3.8 | — | Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779). |
| 3.9 | — | 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). |
| 3.10 | — | 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). |
| 4.1 | — | Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.7 to Amendment No. 1 to our Registration Statement on Form S-3, file No. 333-128282). |
| 4.2 | — | Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LBI Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006). |
| 4.3 | — | Registration Rights Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007). |
| 10.1 | — | Fourth Amended and Restated Credit Agreement, dated November 1, 2005, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005). |
| 10.2 | — | First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006). |
| 10.3 | — | Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006). |

| Number | | Description |
|---|---|---|
| 10.4 | — | Third Amendment to Fourth Amended and Restated Credit Agreement, effective as of March 28, 2007, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007). |
| 10.5 | — | Fifth Amendment and Consent to Fourth Amended and Restated Credit Agreement, effective as of November 7, 2008, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008). |
| 10.6* | — | Sixth Amendment to Fourth Amended and Restated Credit Agreement, effective as of February 27, 2009, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties. |
| 10.7 | — | Commitment Increase Agreement, dated as of September 19, 2007, among Crosstex Energy, L.P., Bank of America, N.A., and certain lenders party thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated September 19, 2007, filed with the Commission on September 24, 2007). |
| 10.8 | — | Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006). |
| 10.9 | — | Letter Amendment No. 1 to Amended and Restated Note Purchase Agreement, effective as of March 30, 2007, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007). |
| 10.10 | — | Waiver and Letter Amendment No. 3 to Amended and Restated Note Purchase Agreement, effective as of November 7, 2008, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008). |
| 10.11* | — | Letter Amendment No. 4 to Amended and Restated Note Purchase Agreement, effective as of February 27, 2009, among Crosstex Energy, L.P. Prudential Investment Management, Inc. and certain other parties. |
| 10.12 | — | Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006). |
| 10.13† | — | Crosstex Energy GP, LLC Long-Term Incentive Plan, dated July 12, 2002 (incorporated by reference to Exhibit 10.4 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067). |
| 10.14† | — | Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005). |
| 10.15 | — | Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067). |
| 10.16† | — | Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067). |
| 10.17 | — | Senior Subordinated Series D Unit Purchase Agreement, dated as of March 23, 2007, 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 March 23, 2007, filed with the Commission on March 27, 2007). |
| 10.18† | — | Form of Performance Unit Agreement (incorporated by reference to our Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007). |
| 10.19 | — | Common Unit Purchase Agreement, dated as of April 8, 2008, by and among Crosstex Energy, L.P. and each of the Purchasers set forth Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Form 8-K dated April 9, 2008). |

| Number | | Description |
|---|---|---|
| 21.1* | — | List of Subsidiaries. |
| 23.1* | — | Consent of KPMG LLP. |
| 23.2* | — | Consent of KPMG LLP. |
| 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. |
| 99.1* | — | Consolidated Balance Sheet of Crosstex Energy GP, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2008. |

* Filed herewith.

† As required by Item 14(a)(3), this exhibit is identified as a compensatory benefit plan or arrangement

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 2nd day of March 2009.

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC, its general partner

By: /s/ BARRY E. DAVIS
Barry E. Davis,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below on the dates indicated by the following persons on behalf of the Registrant and in the capacities with Crosstex Energy GP, LLC, general partner of Crosstex Energy GP, L.P., general partner of the Registrant, indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ BARRY E. DAVIS<br>Barry E. Davis | President, Chief Executive Officer and Director (Principal Executive Officer) | March 2, 2009 |
| /s/ LELDON E. ECHOLS<br>Leldon E. Echols | Director | March 2, 2009 |
| /s/ BRYAN H. LAWRENCE<br>Bryan H. Lawrence | Director | March 2, 2009 |
| /s/ SHELDON B. LUBAR<br>Sheldon B. Lubar | Director | March 2, 2009 |
| /s/ CECIL E. MARTIN<br>Cecil E. Martin | Director | March 2, 2009 |
| /s/ KYLE D. VANN<br>Kyle D. Vann | Director | March 2, 2009 |
| /s/ WILLIAM W. DAVIS<br>William W. Davis | Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer) | March 2, 2009 |

**INDEX TO FINANCIAL STATEMENTS**

**MANAGEMENT'S REPORT ON**
**INTERNAL CONTROL OVER FINANCIAL REPORTING**

Management of Crosstex Energy GP, LLC is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for Crosstex Energy, L.P. (the "Partnership"). As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended), internal control over financial reporting is a process designed by, or under the supervision of Crosstex Energy GP, LLC's principal executive and principal financial officers and effected by its Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles.

The Partnership's internal control over financial reporting is supported by written policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the Partnership's transactions and dispositions of the Partnership's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the consolidated financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the Partnership are being made only in accordance with authorization of the Crosstex Energy GP, LLC's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Partnership's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In connection with the preparation of the Partnership's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2008, the Partnership's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG LLP, the independent registered public accounting firm that audited the Partnership's consolidated financial statements included in this report, has issued an attestation report on the Partnership's internal control over financial reporting, a copy of which appears on page F-4 of this Annual Report on Form 10-K.

**Report of Independent Registered Public Accounting Firm**

The Partners
Crosstex Energy, L.P.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2008 and 2007 and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2008. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedule. These consolidated financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Crosstex Energy, L.P. and subsidiaries as of December 31, 2008 and 2007 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 2, 2009, expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
March 2, 2009

**Report of Independent Registered Public Accounting Firm**

**The Partners**
**Crosstex Energy, L.P.:**

We have audited Crosstex Energy, L.P.'s internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Partnership as of December 31, 2008 and 2007, and the related consolidated statements of operations, stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2008, and our report dated March 2, 2009 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
March 2, 2009

**CROSSTEX ENERGY, L.P.**

**Consolidated Balance Sheets**

| | December 31, 2008 | December 31, 2007 |
|---|---|---|
| | (In thousands except unit data) | |
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 1,636 | $ 142 |
| Accounts receivable: | | |
| Trade, net of allowance for bad debts of $3,655 and $985, respectively | 49,185 | 46,441 |
| Accrued revenues | 292,668 | 443,448 |
| Imbalances | 3,893 | 3,865 |
| Affiliated companies | 110 | 38 |
| Note receivable | 375 | 1,026 |
| Other | 7,243 | 2,531 |
| Fair value of derivative assets | 27,166 | 8,589 |
| Natural gas and natural gas liquids, prepaid expenses and other | 9,645 | 16,062 |
| Total current assets | 391,921 | 522,142 |
| Property and equipment: | | |
| Transmission assets | 474,771 | 468,692 |
| Gathering systems | 614,572 | 460,420 |
| Gas plants | 577,250 | 565,415 |
| Other property and equipment | 70,618 | 64,073 |
| Construction in process | 86,462 | 79,889 |
| Total property and equipment | 1,823,673 | 1,638,489 |
| Accumulated depreciation | (296,393) | (213,327) |
| Total property and equipment, net | 1,527,280 | 1,425,162 |
| Fair value of derivative assets | 4,628 | 1,337 |
| Intangible assets, net of accumulated amortization of $89,231 and $60,118, respectively | 578,096 | 610,076 |
| Goodwill | 19,673 | 24,540 |
| Other assets, net | 11,668 | 9,617 |
| Total assets | $ 2,533,266 | $ 2,592,874 |
| **LIABILITIES AND PARTNERS' EQUITY** | | |
| Current liabilities: | | |
| Drafts payable | $ 21,514 | $ 28,931 |
| Accounts payable | 23,879 | 13,727 |
| Accrued gas purchases | 270,229 | 427,293 |
| Accrued imbalances payable | 7,100 | 9,447 |
| Fair value of derivative liabilities | 28,506 | 21,066 |
| Current portion of long-term debt | 9,412 | 9,412 |
| Other current liabilities | 64,191 | 59,154 |
| Total current liabilities | 424,831 | 569,030 |
| Long-term debt | 1,254,294 | 1,213,706 |
| Other long-term liabilities | 24,708 | 3,553 |
| Deferred tax liability | 8,727 | 8,518 |
| Fair value of derivative liabilities | 22,775 | 9,426 |
| Minority interest | 3,510 | 3,815 |
| Commitments and contingencies | — | — |
| Partners' equity: | | |
| Common unitholders (44,908,522 and 23,868,041 units issued and outstanding at December 31, 2008 and 2007, respectively) | 674,564 | 337,171 |
| Subordinated unitholders (4,668,000 units issued and outstanding at December 31, 2007) | — | (14,679) |
| Senior subordinated series C unitholders (12,829,650 units issued and outstanding at December 31, 2007) | — | 359,319 |
| Senior subordinated series D unitholders (3,875,340 units issued and outstanding at December 31, 2008 and 2007) | 99,942 | 99,942 |
| General partner interest (2% interest with 995,556 and 923,286 equivalent units outstanding at December 31, 2008 and 2007) | 16,805 | 24,551 |
| Accumulated other comprehensive income (loss) | 3,110 | (21,478) |
| Total partners' equity | 794,421 | 784,826 |
| Total liabilities and partners' equity | $ 2,533,266 | $ 2,592,874 |

See accompanying notes to consolidated financial statements.

**CROSSTEX ENERGY, L.P.**

**Consolidated Statements of Operations**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | (In thousands except per unit data) | | |
| Revenues: | | | |
| Midstream | $ 4,838,747 | $ 3,791,316 | $ 3,075,481 |
| Treating | 64,953 | 53,682 | 52,095 |
| Profit on energy trading activities | 3,349 | 4,090 | 2,510 |
| Total revenues | 4,907,049 | 3,849,088 | 3,130,086 |
| Operating costs and expenses: | | | |
| Midstream purchased gas | 4,471,308 | 3,468,924 | 2,859,815 |
| Treating purchased gas | 14,579 | 7,892 | 9,463 |
| Operating expenses | 169,048 | 125,149 | 98,794 |
| General and administrative | 71,005 | 61,528 | 45,694 |
| Gain on derivatives | (12,203) | (6,628) | (1,591) |
| Gain on sale of property | (1,519) | (1,667) | (2,108) |
| Impairments | 30,436 | — | — |
| Depreciation and amortization | 131,187 | 106,639 | 80,518 |
| Total operating costs and expenses | 4,873,841 | 3,761,837 | 3,090,585 |
| Operating income | 33,208 | 87,251 | 39,501 |
| Other income (expense): | | | |
| Interest expense, net of interest income | (102,675) | (79,403) | (51,427) |
| Other income | 27,757 | 683 | 183 |
| Total other income (expense) | (74,918) | (78,720) | (51,244) |
| Income (loss) from continuing operations before minority interest, income taxes and cumulative effect of change in accounting principle | (41,710) | 8,531 | (11,743) |
| Minority interest in subsidiary | (311) | (160) | (231) |
| Income tax provision | (2,765) | (964) | (222) |
| Income (loss) from continuing operations before discontinued operations and cumulative effect of changes in accounting principle | (44,786) | 7,407 | (12,196) |
| Discontinued Operations: | | | |
| Income from discontinued operations | 5,752 | 6,482 | 7,316 |
| Gain on sale of discontinued operations | 49,805 | — | — |
| Discontinued operations | 55,557 | 6,482 | 7,316 |
| Net income (loss) before cumulative effect of change in accounting principle | 10,771 | 13,889 | (4,880) |
| Cumulative effect of change in accounting principle | — | — | 689 |
| Net income (loss) | $ 10,771 | $ 13,889 | $ (4,191) |
| General partner interest in net income | $ 26,415 | $ 19,252 | $ 16,456 |
| Limited partners' interest in net income (loss) | $ (15,644) | $ (5,363) | $ (20,647) |
| Net income (loss) per limited partners' unit: | | | |
| Basic and diluted common unit | $ (3.23) | $ (0.20) | $ (1.09) |
| Basic and diluted senior subordinated series A units (see Note 9(e)) | $ — | $ — | $ 5.31 |
| Basic and diluted senior subordinated series C units (see Note 9(e)) | $ 9.44 | $ — | $ — |
| Basic and diluted senior subordinated series D units (see Note 9(e)) | $ — | $ — | $ — |

See accompanying notes to consolidated financial statements.

**CROSSTEX ENERGY, L.P.**

**Consolidated Statements of Changes in Partners' Equity**
**Years ended December 31, 2008, 2007 and 2006**

| | Common Units | | Subordinated Units | | Sr. Subordinated Units | | Sr. Subordinated C Units | | Sr. Subordinated D Units | | General Partner Interest | | Accumulated Other Comprehensive Income (loss) | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $ | Units | $ | Units | $ | Units | $ | Units | $ | Units | $ | Units | | |
| | | | | | | | (In thousands) | | | | | | | |
| Balance, December 31, 2005 | $ 326,617 | 15,465 | $ 16,462 | 9,334 | $ 49,921 | 1,495 | $ — | — | $ — | — | $ 11,522 | 537 | $ (3,237) | $ 401,285 |
| Proceeds from exercise of unit options | 3,328 | 305 | — | — | — | — | — | — | — | — | — | — | — | 3,328 |
| Issuance of Sr. subordinated series C units | — | — | — | — | — | — | 359,319 | 12,830 | — | — | — | — | — | 359,319 |
| Conversion of subordinated units | 52,195 | 3,829 | (2,274) | (2,333) | (49,921) | (1,495) | — | — | — | — | — | — | — | — |
| Conversion of common units for restricted units | — | 17 | — | — | — | — | — | — | — | — | — | — | — | — |
| Capital contributions | — | — | — | — | — | — | — | — | — | — | 9,273 | 268 | — | 9,273 |
| Stock-based compensation | 3,122 | — | 1,114 | — | — | — | — | — | — | — | 3,632 | — | — | 7,868 |
| Distributions | (39,725) | — | (16,102) | — | — | — | — | — | — | — | (20,411) | — | — | (76,238) |
| Net income (loss) | (15,045) | — | (5,602) | — | — | — | — | — | — | — | 16,456 | — | — | (4,191) |
| Hedging gains or losses reclassified to earnings | — | — | — | — | — | — | — | — | — | — | — | — | (4,875) | (4,875) |
| Adjustment in fair value of derivatives | — | — | — | — | — | — | — | — | — | — | — | — | 16,108 | 16,108 |
| Balance, December 31, 2006 | 330,492 | 19,616 | (6,402) | 7,001 | — | — | 359,319 | 12,830 | — | — | 20,472 | 805 | 7,996 | 711,877 |
| Issuance of common units | 57,550 | 1,800 | — | — | — | — | — | — | — | — | — | — | — | 57,550 |
| Proceeds from exercise of unit options | 1,598 | 90 | — | — | — | — | — | — | — | — | — | — | — | 1,598 |
| Issuance of Sr. subordinated series D units | — | — | — | — | — | — | — | — | 99,942 | 3,875 | — | — | — | 99,942 |
| Conversion of subordinated units | (3,872) | 2,333 | 3,872 | (2,333) | — | — | — | — | — | — | — | — | — | — |
| Conversion of restricted units for common units, net of units withheld for taxes | (329) | 29 | — | — | — | — | — | — | — | — | — | — | — | (329) |
| Capital contributions | — | — | — | — | — | — | — | — | — | — | 4,014 | 118 | — | 4,014 |
| Stock-based compensation | 5,478 | — | 1,228 | — | — | — | — | — | — | — | 5,578 | — | — | 12,284 |
| Distributions | (49,810) | — | (11,950) | — | — | — | — | — | — | — | (24,765) | — | — | (86,525) |
| Net income (loss) | (3,936) | — | (1,427) | — | — | — | — | — | — | — | 19,252 | — | — | 13,889 |
| Hedging gains or losses reclassified to earnings | — | — | — | — | — | — | — | — | — | — | — | — | (3,706) | (3,706) |
| Adjustment in fair value of derivatives | — | — | — | — | — | — | — | — | — | — | — | — | (25,768) | (25,768) |
| Balance December 31, 2007 | 337,171 | 23,868 | (14,679) | 4,668 | — | — | 359,319 | 12,830 | 99,942 | 3,875 | 24,551 | 923 | (21,478) | 784,826 |
| Issuance of common units | 99,888 | 3,333 | — | — | — | — | — | — | — | — | — | — | — | 99,888 |
| Proceeds from exercise of unit options | 850 | 57 | — | — | — | — | — | — | — | — | — | — | — | 850 |
| Conversion of subordinated units | 341,816 | 17,498 | 17,503 | (4,668) | — | — | (359,319) | (12,830) | — | — | — | — | — | — |
| Conversion of restricted units for common units, net of units withheld for taxes | (1,536) | 153 | — | — | — | — | — | — | — | — | — | — | — | (1,536) |
| Capital contributions | — | — | — | — | — | — | — | — | — | — | 2,193 | 73 | — | 2,193 |
| Stock-based compensation | 6,337 | — | 109 | — | — | — | — | — | — | — | 4,797 | — | — | 11,243 |
| Distributions | (94,404) | — | (2,847) | — | — | — | — | — | — | — | (41,151) | — | — | (138,402) |
| Net income (loss) | (15,558) | — | (86) | — | — | — | — | — | — | — | 26,415 | — | — | 10,771 |
| Hedging gains or losses reclassified to earnings | — | — | — | — | — | — | — | — | — | — | — | — | 20,840 | 20,840 |
| Adjustment in fair value of derivatives | — | — | — | — | — | — | — | — | — | — | — | — | 3,748 | 3,748 |
| Balance December 31, 2008 | $ 674,564 | 44,909 | $ — | — | $ — | — | $ — | — | $ 99,942 | 3,875 | $ 16,805 | 996 | $ 3,110 | $ 794,421 |

See accompanying notes to consolidated financial statements.

**CROSSTEX ENERGY, L.P.**

**Consolidated Statements of Comprehensive Income**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (In thousands) | |
| Net income (loss) | $ 10,771 | $ 13,889 | $ (4,191) |
| Hedging gains or losses reclassified to earnings | 20,840 | (3,706) | (4,875) |
| Adjustment in fair value of derivatives | 3,748 | (25,768) | 16,108 |
| Comprehensive income (loss) | $ 35,359 | $ (15,585) | $ 7,042 |

See accompanying notes to consolidated financial statements.

**CROSSTEX ENERGY, L.P.**

**Consolidated Statements of Cash Flows**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (In thousands) | |
| Cash flows from operating activities: | | | |
| Net income (loss) | $ 10,771 | $ 13,889 | $ (4,191) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depreciation and amortization | 132,899 | 108,880 | 82,731 |
| Non-cash stock-based compensation | 11,243 | 12,284 | 8,557 |
| Cumulative effect of change in accounting principle | — | — | (689) |
| Gain on sale of property | (51,325) | (1,667) | (2,108) |
| Impairment | 30,436 | — | — |
| Deferred tax expense | 172 | 253 | 490 |
| Minority interest in subsidiary | 311 | 160 | 231 |
| Non-cash derivatives loss | 23,510 | 2,418 | 550 |
| Amortization of debt issue costs | 2,854 | 2,639 | 2,694 |
| Changes in assets and liabilities, net of acquisition effects: | | | |
| Accounts receivable, accrued revenue and other | 156,248 | (121,300) | 77,365 |
| Natural gas and natural gas liquids, prepaid expenses and other | 5,176 | (5,566) | 13,071 |
| Accounts payable, accrued gas purchases and other accrued liabilities | (148,545) | 101,993 | (65,691) |
| Fair value of derivatives | — | 835 | — |
| Net cash provided by operating activities | 173,750 | 114,818 | 113,010 |
| Cash flows from investing activities: | | | |
| Additions to property and equipment | (275,590) | (414,452) | (314,766) |
| Acquisitions and asset purchases | — | — | (576,110) |
| Proceeds from sales of property | 88,780 | 3,070 | 5,051 |
| Net cash used in investing activities | (186,810) | (411,382) | (885,825) |
| Cash flows from financing activities: | | | |
| Proceeds from borrowings | 1,743,580 | 1,189,500 | 1,708,500 |
| Payments on borrowings | (1,702,992) | (953,512) | (1,244,021) |
| Proceeds from capital lease obligations | 28,010 | 3,553 | — |
| Payments on capital lease obligations | (4,101) | — | — |
| Increase (decrease) in drafts payable | (7,417) | (19,017) | 18,094 |
| Debt refinancing costs | (4,903) | (892) | (5,646) |
| Conversion of restricted units, net of units withheld for taxes | (1,536) | (329) | — |
| Distributions to minority interest party | (725) | — | (375) |
| Distribution to partners | (138,402) | (86,525) | (76,238) |
| Proceeds from exercise of unit options | 850 | 1,598 | 3,328 |
| Net proceeds from common unit offerings | 99,888 | 57,550 | — |
| Issuance of subordinated units | — | 99,942 | 359,319 |
| Contribution from partners | 2,193 | 4,014 | 9,273 |
| Contributions from minority interest party | 109 | — | — |
| Net cash provided by financing activities | 14,554 | 295,882 | 772,234 |
| Net increase (decrease) in cash and cash equivalents | 1,494 | (682) | (581) |
| Cash and cash equivalents, beginning of period | 142 | 824 | 1,405 |
| Cash and cash equivalents, end of period | $ 1,636 | $ 142 | $ 824 |
| Cash paid for interest | $ 76,291 | $ 79,648 | $ 46,794 |
| Cash paid (refund) for income taxes | $ 1,371 | $ 38 | $ (847) |

See accompanying notes to consolidated financial statements.

**CROSSTEX ENERGY, L.P.**

**Notes to Consolidated Financial Statements**
**December 31, 2008 and 2007**

## (1) Organization and Summary of Significant Agreements

### *(a) Description of Business*

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

### *(b) Partnership Ownership*

Crosstex Energy GP, L.P., the general partner of the Partnership, is an indirect wholly-owned subsidiary of Crosstex Energy, Inc. (CEI). As of December 31, 2008, CEI owns 16,414,830 common units in the Partnership through its wholly-owned subsidiaries. As of December 31, 2008, CEI owned 34.0% of the limited partner interests in the Partnership and officers and directors owned 1.02% of the limited partnership interests. The remaining units are held by the public.

### *(c) Basis of Presentation*

The accompanying consolidated financial statements include the assets, liabilities, and results of operations of the Partnership and its wholly-owned subsidiaries. The Partnership proportionately consolidates its undivided 59.27% interest in a gas processing plant acquired by the Partnership in November 2005 (23.85%) and May 2006 (35.42%). In January 2004, the Partnership adopted FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities* (FIN No. 46R) and began consolidating its joint venture interest in Crosstex DC Gathering, J.V. (CDC) as discussed more fully in Note 5. The consolidated operations are hereafter referred to herein collectively as the "Partnership." All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for the prior years to conform to the current presentation.

## (2) Significant Accounting Policies

### *(a) Management's Use of Estimates*

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

### *(b) Cash and Cash Equivalents*

The Partnership considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

### *(c) Natural Gas and Natural Gas Liquids Inventory*

The Partnership's inventories of products consist of natural gas and NGLs. The Partnership reports these assets at the lower of cost or market.

***(d) Property, Plant, and Equipment***

Property, plant and equipment consist of intrastate gas transmission systems, gas gathering systems, industrial supply pipelines, NGL pipelines, natural gas processing plants, NGL fractionation plants, dew point control and gas treating plants.

Other property and equipment is primarily comprised of computer software and equipment, furniture, fixtures, leasehold improvements and office equipment. Property, plant and equipment are recorded at cost. Gas required to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest costs are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use. Interest costs totaling $2.7 million, $4.8 million, and $5.4 million were capitalized for the years ended December 31, 2008, 2007 and 2006, respectively.

Depreciation is provided using the straight-line method based on the estimated useful life of each asset, as follows:

| | Useful Lives |
|---|---|
| Transmission assets | 15-30 years |
| Gathering systems | 7-15 years |
| Gas treating and gas processing plants | 15 years |
| Other property and equipment | 3-10 years |

Depreciation expense of $98.0 million, $78.3 million and $66.8 million was recorded for the years ended December 31, 2008, 2007 and 2006, respectively.

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If an impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset.

When determining whether impairment of one of our long-lived assets has occurred, the Partnership must estimate the undiscounted cash flows attributable to the asset. The Partnership's estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors. Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

The Partnership recorded impairments to long-lived assets of $25.6 million during the year ending December 31, 2008. See Note 3(c) for further details on the long-lived assets impaired. No impairments were incurred during the years ended December 31, 2007 and 2006.

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, also requires long-lived assets being held for sale or disposed of to be presented in the financial statements separately. During the third quarter of 2008 the Partnership held for sale its undivided 12.4% interest in the Seminole gas processing plant. The sale was finalized on November 17, 2008. All operating results for the Seminole plant are recorded in discontinued operating income and the gain on the disposition of the plant is

recorded in gain on sale of discontinued operations. See Note 3(d) for further information on discontinued operations.

***(e) Goodwill and Intangibles***

The Partnership has approximately $19.7 million and $24.5 million of goodwill at December 31, 2008 and 2007, respectively. Goodwill created in the formation of the Partnership of $4.9 million net book value associated with the Midstream assets was impaired during the year ending December 31, 2008. The goodwill remaining in the Partnership is attributable to Treating assets acquired during 2005 and 2006. See Note 4 for further details on the impairment of goodwill on the Midstream assets. Goodwill will continue to be assessed at least annually for impairment.

Intangible assets consist of customer relationships and the value of the dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems. The Chief acquisition, as discussed in Note 3(a), included $395.6 million of such intangibles, including the Devon Energy Corporation (Devon) gas gathering agreement. Intangible assets other than the intangibles associated with the Chief acquisition are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from three to 15 years. The intangible assets associated with the Chief acquisition are being amortized using the units of throughput method of amortization. The weighted average amortization period for intangible assets is 17.7 years. Amortization of intangibles was approximately $33.2 million, $28.4 million and $13.8 million for the years ended December 31, 2008, 2007 and 2006, respectively.

The following table summarizes the Company's estimated aggregate amortization expense for the next five years (in thousands):

| | |
|---|---|
| 2009 | $ 39,810 |
| 2010 | 40,193 |
| 2011 | 44,735 |
| 2012 | 47,511 |
| 2013 | 47,620 |
| Thereafter | 358,227 |
| Total | $ 578,096 |

***(f) Other Assets***

Unamortized debt issuance costs totaling $11.7 million and $9.6 million as of December 31, 2008 and 2007, respectively, are included in other assets, net. Debt issuance costs are amortized into interest expense using the effective-interest method over the term of the debt for the senior secured notes. Debt issuance costs are amortized using the straight-line method over the term of the debt for the bank credit facility because borrowings under the bank credit facility cannot be forecasted for an effective-interest computation.

***(g) Gas Imbalance Accounting***

Quantities of natural gas and NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. The Partnership had imbalance payables of $7.1 million and $9.4 million at December 31, 2008 and 2007, respectively, which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $3.9 million at December 31, 2008 and 2007, which are carried at the lower of cost or market value.

***(h) Asset Retirement Obligations***

In March 2005, the FASB issued Interpretation No. 47, "*Accounting for Conditional Asset Retirement Obligations*" (FIN 47) which became effective at December 31, 2005. FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, "*Accounting for Asset Retirement Obligations*", refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FIN 47 provides that a liability for the fair value of a conditional asset retirement activity should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB Statement No. 143. The Partnership did not provide any asset retirement obligations as of December 31, 2008 or 2007 because it does not have sufficient information as set forth in FIN 47 to reasonably estimate such obligations and the Partnership has no current intention of discontinuing use of any significant assets.

***(i) Revenue Recognition***

The Partnership recognizes revenue for sales or services at the time the natural gas, or NGLs are delivered or at the time the service is performed. The Partnership generally accrues one to two months of sales and the related gas purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates. The Partnership's purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the statements of operations in accordance with EITF Issue No. 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Except for fee based arrangements and the Partnership's energy trading activities related to its "off-system" gas marketing operations discussed in Note 2(k), the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, schedules the transportation and assumes credit risk.

The Partnership accounts for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

***(j) Derivatives***

The Partnership uses derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities",* requires that all derivatives be recorded on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet in fair value of derivative assets or liabilities.

Realized and unrealized gains and losses on derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, are recorded as gain or loss on derivatives in the consolidated statement of operations. Unrealized gains and losses on effective cash flow hedge derivatives are recorded as a component of accumulated other comprehensive income. When the hedged transaction occurs, the realized gain or loss on the hedge derivative is transferred from accumulated other comprehensive income to earnings. Realized gains and losses on commodity hedge derivatives are recognized in revenues, and realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

***(k) Energy Trading Activities***

The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that the Partnership does not own. The Partnership refers to these activities as its energy trading activities. In some cases, the

Partnership earns an agency fee from the producer for arranging the marketing of the producer's natural gas or NGLs. In other cases, the Partnership purchases the natural gas or NGLs from the producer and enters into a sales contract with another party to sell the natural gas or NGLs. The revenue and cost of sales for energy trading activities are shown net in the consolidated statement of operations.

The Partnership manages its price risk related to future physical purchase or sale commitments for its energy trading activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance the Partnership's future commitments and significantly reduce its risk to the movement in natural gas and NGL prices. However, the Partnership is subject to counter-party risk for both the physical and financial contracts. The Partnership's energy trading contracts qualify as derivatives, and accordingly, the Partnership continues to use mark-to-market accounting for both physical and financial contracts of its energy trading activities. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Partnership's energy trading activities are recognized in earnings as gain or loss on derivatives immediately.

Net margins earned on settled contracts from the Partnership's energy trading activities included in profit on energy trading activities in the consolidated statement of operations were $3.3 million, $4.1 million and $2.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Energy trading contract volumes that were physically settled were as follows (in MMBtus):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Volumes purchased and sold | 31,003,000 | 34,432,000 | 50,563,000 |

***(l) Comprehensive Income (Loss)***

Comprehensive income includes net income (loss) and other comprehensive income, which includes, but is not limited to, unrealized gains and losses on marketable securities, foreign currency translation adjustments, minimum pension liability adjustments and unrealized gains and losses on derivative financial instruments.

Pursuant to SFAS No. 133, the Partnership records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

***(m) Legal Costs Expected to be Incurred in Connection with a Loss Contingency***

Legal costs incurred in connection with a loss contingency are expensed as incurred.

***(n) Concentrations of Credit Risk***

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited since the Partnership's customers represent a broad and diverse group of energy marketers and end users. In addition, the Partnership continually monitors and reviews credit exposure to its marketing counter-parties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. The Partnership records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Partnership had a reserve for uncollectible receivables as of December 31, 2008, 2007 and 2006 of $3.7 million, $1.0 million and $0.6 million, respectively. The increase in reserve in 2008 primarily relates to SemStream, L.P. See Note 16(e) for a discussion of the bankruptcy filing of SemStream, L.P. and related subsidiaries.

During 2008, 2007 and 2006 Dow Hydrocarbons accounted for 11.0%, 11.8% and 13.4%, respectively, of the consolidated revenue of the Partnership. As the Partnership continues to grow and expand, the relationship between individual customer sales and consolidated total sales is expected to continue to change. While this customer

represents a significant percentage of revenues, the loss of this customer would not have a material adverse impact on the Partnership's results of operations.

***(o) Environmental Costs***

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For the years ended December 31, 2008, 2007 and 2006, such expenditures were not significant.

***(p) Option Plans***

Effective January 1, 2006, the Partnership adopted the provisions of SFAS No. 123R, "*Share-Based Payment"* (SFAS No. 123R) which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements.

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

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 plans awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Cost of share-based compensation charged to general and administrative expense | $ 9,364 | $ 10,442 | $ 7,426 |
| Cost of share-based compensation charged to operating expense | 1,879 | 1,842 | 1,131 |
| Total amount charged to income before cumulative effect of accounting change | $ 11,243 | $ 12,284 | $ 8,557 |

The fair value of each option is estimated on the date of grant using the Black Scholes option-pricing model as disclosed in Note 11 — Employee Incentive Plans.

***(q) Recent Accounting Pronouncements***

In October 2008, as a result of the recent credit crisis, the FASB issued FSP No. FAS 157-3, "*Determining the Fair Value of a Financial Asset in a Market That is Not Active"* ("FSP FAS 157-3"). FSP FAS 157-3 clarifies the application of SFAS No. 157 in a market that is not active and provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. FSP FAS 157-3 is effective upon issuance, for companies that have adopted SFAS No. 157. The

Partnership has evaluated the FSP and determined that this standard has no impact on its results of operations, cash flows or financial position for this reporting period.

In June 2008, the Financial Accounting Standards Board (FASB) issued Staff Position FSP EITF 03-6-1 (the FSP) which requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in EITF Issue No. 03-6, "Participating Securities and the Two-Class Method under FASB Statement No. 128," and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB Statement No. 128, *Earnings per Share.* The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Upon adoption, the Partnership will consider restricted shares with nonforfeitable dividend rights in the calculation of earnings per share and will adjust all prior reporting periods retrospectively to conform to the requirements, although the impact should not be material.

In February 2007, the FASB issued SFAS No. 159, *"Fair Value Option for Financial Assets and Financial Liabilities-Including an amendment to FASB Statement No. 115"* ("SFAS 159"). SFAS 159 permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 was adopted effective January 1, 2008 and did not have a material impact on our financial statements.

In December 2007, the FASB issued SFAS No. 141R, *"Business Combinations"* ("SFAS 141R") and SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements"* ("SFAS 160"). SFAS 141R requires most identifiable assets, liabilities, noncontrolling interests and goodwill acquired in a business combination to be recorded at "full fair value." The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under SFAS 141R, all business combinations will be accounted for by applying the acquisition method. SFAS 141R is effective for periods beginning on or after December 15, 2008. SFAS 160 will require noncontrolling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for noncontrolling interests and transactions with noncontrolling interest holders in consolidated financial statements. SFAS 160 is effective for periods beginning on or after December 15, 2008 and will be applied prospectively to all noncontrolling interests, including any that arose before the effective date, except that comparative period information must be recast to classify noncontrolling interests in equity, attribute net income and other comprehensive income to noncontrolling interests and provide other disclosures required by SFAS 160.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* ("SFAS No. 162"). SFAS No. 162 is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS No. 162 is effective for fiscal years beginning after November 15, 2008. The Partnership is currently evaluating the potential impact, if any, of the adoption of SFAS No. 162 on our consolidated financial statements.

In March of 2008, the FASB issued SFAS No. 161, *"Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133"* ("SFAS 161"). SFAS 161 requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under SFAS 133 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. SFAS 161 is effective for fiscal years beginning after November 15, 2008. The principal impact to the Partnership will be to require expanded disclosure regarding derivative instruments.

**(3) Significant Asset Acquisitions, Impairments, and Dispositions, Including Discontinued Operations**

***(a) Acquisitions***

On June 29, 2006, the Partnership expanded its operations in the north Texas area through the acquisition of the natural gas gathering pipeline systems and related facilities of Chief Holdings, LLC or Chief in the Barnett Shale for $475.3 million. The acquired systems, which we refer to in conjunction with the NTP and other facilities in the area as the north Texas assets, included gathering pipeline, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower.

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

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

***(b) Dispositions***

In November 2008, the Partnership sold a contract right for firm transportation capacity on a third party pipeline to an unaffiliated third party for $20.0 million. The entire amount of such proceeds is reflected in other income in the consolidated statement of operations.

***(c) Long-Lived Asset Impairments***

Impairments of $25.6 million were recorded in the year ended December 31, 2008 related to long-lived assets. The impairments are comprised of:

- $17.8 million related to the Blue Water gas processing plant located in south Louisiana — The impairment on the Partnership's 59.27% interest in the Blue Water gas processing plant was recognized because the pipeline company which owns the offshore Blue Water system and supplies gas to the Partnership's Blue Water plant reversed the flow of the gas on its pipeline in early January 2009 thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system. At this time, the Partnership has not found an alternative source of new gas for the Blue Water plant so the plant ceased operations in January 2009. An impairment of $17.8 million was recognized for the carrying amount of the plant in excess of the estimated fair value of the plant as of December 31, 2008. The fair value of the Blue Water plant was determined by using the market and cost approach for valuing the plant. The income approach was not considered because the plant is not in operation.
- $4.1 million related to leasehold improvements — The Partnership had planned to relocate its corporate office during 2008 to a larger office facility. The Partnership had leased office space and was close to completing the renovation of this office space when the global economic decline began impacting its operations in October 2008. On December 31, 2008, the decision was made to cancel the new office lease and not relocate the corporate offices from its existing office location. The impairment relates to the leasehold improvements on the office space for the cancelled lease.

- $2.6 million related to the Arkoma gathering system — The impairment on the Arkoma gathering system was recognized because the Partnership sold this asset in February 2009 for approximately $11.0 million and the carrying amount of the asset exceeded the sale price by approximately $2.6 million.
- $1.0 million related to unused treating equipment — The impairment relates to certain older equipment in the Treating division that will not be used in the Partnership's operations.

***(d) Discontinued Operations***

As part of the Partnership's strategy to increase liquidity in response to the tightening financial markets, the Partnership began marketing a non-strategic asset for sale in late September 2008. In early October 2008, the Partnership entered into an agreement to sell its undivided 12.4% interest in the Seminole gas processing plant to a third party for $85.0 million. The transaction was completed on November 17, 2008. This asset was previously presented in the Partnership's Treating segment. The consolidated balance sheets at December 31, 2008 and 2007 do not reflect the asset held for sale due to the fact that the decision to dispose of the asset occurred after December 31, 2007, and the sale was completed prior to December 31, 2008. The revenues and expenses related to the operations of the asset held for sale have been segregated from continuing operations and reported as discontinued operations for all periods. No income taxes are attributed to income from discontinued operations. Following are revenues, income from discontinued operations and gain on discontinued operations (in thousands):

| | Years Ended December 31 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Treating Revenues | $ 8,539 | $ 11,343 | $ 11,718 |
| Income from Discontinued Operations | $ 5,752 | $ 6,482 | $ 7,316 |
| Gain from Discontinued Operations | $ 49,805 | $ — | $ — |

**(4) Goodwill Impairment**

As of December 31, 2006 and 2007, the carrying amount of goodwill was considered recoverable. In the fourth quarter of 2008, the Partnership determined that the carrying amount of goodwill attributable to the Midstream segment was impaired because of the significant decline in its Midstream operations due to the significant declines in natural gas and NGL prices during the last half of 2008 coupled with the global economic decline. The Partnership determined the estimated fair value of the Midstream reporting unit by calculating the present value of its estimated future cash flows. The Partnership determined the implied fair value of goodwill associated with the Midstream reporting unit by subtracting the estimated fair value of the tangible assets and intangible assets associated with the Midstream reporting unit from the estimated fair value of the unit. The Partnership recognized an impairment loss of $4.9 million in the Midstream segment for the year ended December 31, 2008.

**(5) Investment in Limited Partnerships and Note Receivable**

The Partnership owns a majority interest in Crosstex Denton County Joint Venture (CDC) and consolidates its investment in CDC pursuant to FIN No. 46R. The Partnership manages the business affairs of CDC. The other joint venture partner (the CDC partner) is an unrelated third party who owns and operates a natural gas field located in Denton County, Texas.

In connection with the formation of CDC, the Partnership agreed to loan the CDC partner up to $1.5 million for its initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to the Partnership attributable to CDC partner's share of distributable cash flow to repay the loan. The balance remaining on the note of $0.4 million is included in current notes receivable as of December 31, 2008.

**(6) Long-Term Debt**

As of December 31, 2008 and 2007, long-term debt consisted of the following (in thousands):

| | 2008 | 2007 |
|---|---|---|
| Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2008 and 2007 were 6.33% and 6.71%, respectively | $ 784,000 | $ 734,000 |
| Senior secured notes, weighted average interest rates at December 31, 2008 and 2007 of 8.0% and 6.75%, respectively | 479,706 | 489,118 |
| | 1,263,706 | 1,223,118 |
| Less current portion | (9,412) | (9,412) |
| Debt classified as long-term | $ 1,254,294 | $ 1,213,706 |

*Credit Facility.* In September 2007, the Partnership increased borrowing capacity under the bank credit facility to $1.185 billion. The bank credit facility matures in June 2011. As of December 31, 2008, $850.4 million was outstanding under the bank credit facility, including $66.4 million of letters of credit, leaving approximately $334.6 million available for future borrowing.

Obligations under the bank credit facility are secured by first priority liens on all of the Partnership's material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of the Partnership's equity interests in substantially all of its subsidiaries, and rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by the Partnership's material subsidiaries. The Partnership 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.

On November 7, 2008, the Partnership entered into the Fifth Amendment and Consent (the "Fifth Amendment") to its credit facility with Bank of America, N.A., as administrative agent, and the banks and other parties thereto (the "Bank Lending Group"). The Fifth Amendment amended the agreement governing its credit facility to, among other things, (i) increase the maximum permitted leverage ratio it must maintain for the fiscal quarters ending December 31, 2008 through September 30, 2009, (ii) lower the minimum interest coverage ratio it must maintain for the fiscal quarter ending December 31, 2008 and each fiscal quarter thereafter, (iii) permit it to sell certain assets, (iv) increase the interest rate it pays on the obligations under the credit facility and (v) lower the maximum permitted leverage ratio it must maintain if the Partnership or its subsidiaries incur unsecured note indebtedness.

Due to the continued decline in commodity prices and the deterioration in the processing margins, the Partnership determined that there was a significant risk that the amended terms negotiated in November 2008 would not be sufficient to allow it to operate during 2009 without triggering a covenant default under our bank facility and the senior secured note agreement. On February 27, 2009, the Partnership entered into the Sixth Amendment to the Fourth Amended and Restated Credit Agreement and Consent (the "Sixth Amendment") to its credit facility with Bank Lending Group. Under the Sixth Amendment, borrowings will bear interest at its option at the administrative agent's reference rate plus an applicable margin or London Interbank Offering Rate (LIBOR) plus an applicable margin. The applicable margins for the Partnership's interest rate and letter of credit fees vary quarterly based on the Partnership's leverage ratio as defined by the credit facility (the "Leverage Ratio" generally being computed as total

funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows beginning February 27, 2009:

| Leverage Ratio | Bank Reference Rate Advances(a) | LIBOR Rate Advances(b) | Letter of Credit Fees(c) | Commitment Fees(d) |
|---|---|---|---|---|
| Greater than or equal to 5.00 to 1.00 | 3.00% | 4.00% | 4.00% | 0.50% |
| Greater than or equal to 4.25 to 1.00 and less than 5.00 to 1.00 | 2.50% | 3.50% | 3.50% | 0.50% |
| Greater than or equal to 3.75 to 1.00 and less than 4.25 to 1.00 | 2.25% | 3.25% | 3.25% | 0.50% |
| Less than 3.75 to 1.00 | 1.75% | 2.75% | 2.75% | 0.50% |

(a) The applicable margins for the bank reference rate advances ranged from 0% to 0.25% under the bank credit facility prior to the Fifth and Sixth Amendments. The applicable margin for the bank reference rate advances was paid at the maximum rate of 2.00% under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(b) The applicable margins for the LIBOR rate advances ranged from 1.00% to 1.75% under the bank credit facility prior to the Fifth and Sixth Amendments. The applicable margin for the bank reference rate advances was paid at the maximum rate of 3.00% under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(c) The letter of credit fees ranged from 1.00% to 1.75% per annum plus a fronting fee of 0.125% per annum under the bank credit facility prior to the Fifth and Sixth Amendments. The letter of credit fees were paid at the maximum rate of 3.00% per annum in addition to the fronting fee under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(d) The commitment fees ranged from 0.20% to 0.375% per annum on the unused amount of the credit facility under the bank credit facility prior to the Fifth and Sixth Amendments. The commitment fees were paid at the maximum rate of 0.50% per annum under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

The Sixth Amendment also sets a floor for the LIBOR interest rate of 2.75% per annum, which means, effective as of February 27, 2009, borrowings under the bank credit facility accrue interest at the rate of 6.75% based on the LIBOR rate in effect on such date and our current leverage ratio. Based on the Partnership's forecasted leverage ratios for 2009, it expects the applicable margins to be at the high end of these ranges for its interest rate and letter of credit fees.

Pursuant to the Sixth Amendment, the Partnership must pay a leverage fee if it does not prepay debt and permanently reduce the banks' commitments by the cumulative amounts of $100.0 million on September 30, 2009, $200.0 million on December 31, 2009 and $300.0 million on March 31, 2010. If it fails to meet any de-leveraging target, it must pay a leverage fee on such date, equal to the product of the aggregate commitments outstanding under its bank credit facility and the outstanding amount of senior secured note agreement on such date, and 1.0% on September 30, 2009, 1.0% on December 31, 2009 and 2.0% on March 31, 2010. This leverage fee will accrue on the applicable date, but not be payable until the Partnership refinances its bank credit facility.

Under the Sixth Amendment, the maximum Leverage Ratio (measured quarterly on a rolling four-quarter basis) is as follows:

- 7.25 to 1.00 for the fiscal quarter ending March 31, 2009;
- 8.25 to 1.00 for the fiscal quarters ending June 30, 2009 and September 30, 2009;
- 8.50 to 1.00 for the fiscal quarter ending December 31, 2009;
- 8.00 to 1.00 for the fiscal quarter ending March 31, 2010;
- 6.65 to 1.00 for the fiscal quarter ending June 30, 2010;
- 5.25 to 1.00 for the fiscal quarter ending September 30, 2010;
- 5.00 to 1.00 for the fiscal quarter ending December 31, 2010;

- 4.50 to 1.00 for any fiscal quarters ending March 31, 2011 through March 31, 2012; and
- 4.25 to 1.00 for any fiscal quarters ending June 30, 2012 and thereafter.

The minimum cash interest coverage ratio (as defined in the agreement, measured quarterly on a rolling four-quarter basis) is as follows under the Sixth Amendment:

- 1.75 to 1.00 for the fiscal quarters ending March 31, 2009;
- 1.50 to 1.00 for the fiscal quarter ending June 30, 2009;
- 1.30 to 1.00 for the fiscal quarter ending September 30, 2009;
- 1.15 to 1.00 for the fiscal quarter ending December 31, 2009;
- 1.25 to 1.00 for the fiscal quarter ending March 31, 2010;
- 1.50 to 1.00 for the fiscal quarter ending June 30, 2010;
- 1.75 to 1.00 for any fiscal quarter ending September 30, 2010 and December 31, 2010; and
- 2.50 to 1.00 for any fiscal quarter ending March 31, 2011 and thereafter.

Under the Sixth Amendment, no quarterly distributions may be paid to partners unless the PIK notes have been repaid and the Leverage Ratio is less than 4.25 to 1.00. If the Leverage Ratio is between 4.00 to 1.00 and 4.25 to 1.00, the Partnership may make the minimum quarterly distribution of up to $0.25 per unit if the PIK notes have been repaid. If the Leverage Ratio is less than 4.00 to 1.00, the Partnership may make quarterly distributions to partners from available cash as provided by its partnership agreement if the PIK notes have been repaid. The PIK notes are due six months after the earlier of the refinancing or maturity of its bank credit facility. Based on its forecasted leverage ratios for 2009 and its near term ability to refinance its bank credit facility, the Partnership does not anticipate making quarterly distributions during 2009 other than the distribution paid in February 2009 related to fourth quarter 2008 operating results. The Partnership will not be able to make distributions to its unitholders in future periods if its leverage ratio does not improve.

The Sixth Amendment also limits the Partnership's annual capital expenditures (excluding maintenance capital expenditures) to $120.0 million in 2009 and $75.0 million in 2010 and each year thereafter (with unused amounts in any year being carried forward to the next year). It is unlikely that the Partnership will be able to make any acquisitions based on the terms of our credit facility and the current condition of the capital markets because it may only use a portion of the proceeds from the incurrence of unsecured debt and the issuance of equity to make such acquisitions.

The Sixth Amendment also eliminated the accordion in the Partnership's bank credit facility, which previously had permitted it to increase commitments thereunder by certain amounts if any bank was willing to undertake such commitment increase.

The Sixth Amendment also revised the terms for mandatory repayment of outstanding indebtedness from asset sales and proceeds from incurrence of unsecured debt and equity issuances. Proceeds from debt issuances and from equity issuances not required to prepay indebtedness are considered to be "Excess Proceeds" under the amended bank credit agreement. The Partnership may retain all Excess Proceeds. The following table sets forth the amended prepayment terms:

| Leverage Ratio* | % of Net Proceeds from Asset Sales Required for Prepayment | % of Net Proceeds from Debt Issuances Required for Prepayment | % of Net Proceeds from Equity Issuance Required for Prepayment |
|---|---|---|---|
| Greater than or equal to 4.50 | 100% | 100% | 50% |
| Greater or equal to 3.50 and Less than 4.50 | 100% | 50% | 25% |
| Less than 3.50 | 100% | 0% | 0% |

* The Leverage Ratio is to be adjusted to give effect to proceeds from debt or equity issuance and the use of such proceeds for each proportional level of Leverage Ratio.

The prepayments are to be applied pro rata based on total debt (including letter of credit obligations) outstanding under the bank credit agreement and the total debt outstanding under the note agreement described below. Any prepayments of advances on the bank credit facility from proceeds from asset sales, debt or equity issuances will permanently reduce the borrowing capacity or commitment under the facility in an amount equal to 100% of the amount of the prepayment. Any such commitment reduction will not reduce the banks' $300.0 million commitment to issue letters of credit.

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

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- change the nature of our business;
- enter into certain commodity contracts;
- make certain amendments to its or the operating partnership's partnership agreement; and
- engage in transactions with affiliates.

Each of the following will be an event of default under the bank credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;
- certain judgments against us or any of its subsidiaries, in excess of certain allowances;
- certain ERISA events involving the Partnership or its subsidiaries;
- bankruptcy or other insolvency events;
- a change in control (as defined in the credit agreement); and
- the failure of any representation or warranty to be materially true and correct when made.

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under our bank credit facility will immediately become due and payable. If any other event of default exists under the bank credit facility, the lenders may accelerate the maturity of the obligations outstanding under the bank credit facility and exercise other rights and remedies.

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. See Note 13 to the financial statements for a discussion of interest rate swaps.

**CROSSTEX ENERGY, L.P.**

**Notes to Consolidated Financial Statements — (Continued)**

*Senior Secured Notes.* The Partnership entered into a master shelf agreement with an institutional lender in 2003 that was amended in subsequent years to increase availability under the agreement, pursuant to which it issued the following senior secured notes (dollars in thousands):

| Month Issued | Amount | Interest Rate(1) | Maturity | Principal Payment Terms |
|---|---|---|---|---|
| June 2003(2) | $ 30,000 | 9.45% | 7 years | Quarterly payments of $1,765 from June 2006-June 2010 |
| July 2003(2) | 10,000 | 9.38% | 7 years | Quarterly payments of $588 from July 2006-July 2010 |
| June 2004 | 75,000 | 9.46% | 10 years | Annual payments of $15,000 from July 2010-July 2014 |
| November 2005 | 85,000 | 8.73% | 10 years | Annual payments of $17,000 from November 2010-December 2014 |
| March 2006 | 60,000 | 8.82% | 10 years | Annual payments of $12,000 from March 2012-March 2016 |
| July 2006 | 245,000 | 8.46% | 10 years | Annual payments of $49,000 from July 2012-July 2016 |
| Total Issued | 505,000 | | | |
| Principal repaid | (25,294) | | | |
| Balance as of December 31, 2008 | $ 479,706 | | | |

(1) Interest rates have been adjusted to give effect to the 2% interest rate increase under the February 27, 2009 amendment described below.

(2) Principal repayments were $19.4 million and $5.9 million on the June 2003 and July 2003 notes, respectively.

On November 7, 2008, the Partnership amended our senior secured note agreement governing its senior secured notes to, among other things, (i) modify the maximum permitted leverage ratio and lower the minimum interest coverage ratio it must maintain consistent with the ratios under the Fifth Amendment to the bank credit facility, (ii) permit it to sell certain assets and (iii) increase the interest rate it pays on the senior secured notes. The interest rate the Partnership paid on the senior secured notes increased by 1.25% for the fourth quarter of 2008 due to this amendment.

The covenants and terms of default for the senior secured notes are substantially the same as the covenants and default terms under the Partnership's bank credit facility, and therefore the agreements governing the senior secured notes also required amendment in 2009. On February 27, 2009, the Partnership amended its senior note agreements to (i) increase the maximum permitted leverage ratio and to lower the minimum interest coverage ratio it must maintain consistent with the ratios under the Sixth Amendment to the bank credit facility, (ii) revise the mandatory prepayment terms consistent with the terms under the Sixth Amendment to the bank credit facility, (iii) increase the interest rate it pays on the senior secured notes and (iv) provide for the payment of a leverage fee consistent with the terms of bank credit facility. Commencing February 27, 2009 the interest rate the Partnership pays in cash on all of the senior secured notes will increase by 2.25% per annum for each of the fiscal quarters commencing with the quarter ending March 31, 2009 over the comparative interest rates under the senior note agreements prior to the November and February amendments. As a result of this rate increase, the weighted average interest rate on the outstanding balance on the senior secured notes is approximately 9.25% as of February 2009.

Under the amended senior secured note agreement, the senior secured notes will accrue additional interest of 1.25% per annum of the senior secured notes (the "PIK notes") in the form of an increase in the principal amount unless our leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter. All PIK notes will be payable six

months after the maturity of our bank credit facility, which is currently scheduled to mature in June 2011, or six months after refinancing of such indebtedness if prior to the maturity date.

Per the terms of the amended senior note agreement, commencing on the date we refinance our bank credit facility, the interest rate payable in cash on our senior secured notes will increase by 1.25% per annum for any quarter if our leverage ratio as of the most recently ended fiscal quarter was greater than or equal to 4.25 to 1.00. In addition, commencing on June 30, 2012, the interest rate payable in cash on our senior secured notes will increase by 0.50% per annum for any quarter if our leverage as of the most recently ended fiscal quarter was greater than or equal to 4.00 to 1.00, but this incremental interest will not accrue if we are paying the incremental 1.25% per annum of interest described in the preceding sentence.

These notes represent the Partnership's senior secured obligations and will rank *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with the Partnership's obligations under the credit facility, by first priority liens on all of its material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all its equity interests in substantially all of its subsidiaries. The senior secured notes are guaranteed by the Partnership's material subsidiaries.

The senior secured notes issued in 2003 are redeemable, at the Partnership's option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the senior secured note agreement. The senior secured notes issued 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance.

If an event of default resulting from bankruptcy or other insolvency events occurs, the senior secured notes will become immediately due and payable. If any other event of default occurs and is continuing, holders of at least 50.1% in principal amount of the outstanding notes may at any time declare all the notes then outstanding to be immediately due and payable. If an event of default relating to the nonpayment of principal, make-whole amounts or interest occurs, any holder of outstanding notes affected by such event of default may declare all the notes held by such holder to be immediately due and payable.

The senior secured note agreement relating to the notes contains substantially the same covenants and events of default as our bank credit facility.

The Partnership was in compliance with all debt covenants at December 31, 2008 and 2007 and expects to be in compliance with debt covenants for the next twelve months.

*Intercreditor and Collateral Agency Agreement.* In connection with the execution of the senior secured note agreement, the lenders under our bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by the Partnership and its subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under our bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under our bank credit facility, holders of our senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under our bank credit facility and the senior secured note agreement. On February 27, 2009, the holders of the Partnership's senior secured notes and a majority of the banks under its bank credit facility entered into an amendment to the Intercreditor and Collateral Agency Agreement, which provides that the PIK notes and certain treasury management obligations will be secured by the collateral for its bank credit facility and the senior secured notes, but only paid with proceeds of collateral after obligations under its bank credit facility and the senior secured notes are paid in full.

*Maturities.* Maturities for the long-term debt as of December 31, 2008 are as follows (in thousands):

| | |
|---|---|
| 2009 | $ 9,412 |
| 2010 | 20,294 |
| 2011 | 816,000 |
| 2012 | 93,000 |
| 2013 | 93,000 |
| Thereafter | 232,000 |

**(7) Other Long-Term Liabilities**

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

| | Years Ended December 31, | |
|---|---|---|
| | 2008 | 2007 |
| Compressor equipment | $ 28,890 | $ 4,011 |
| Less: Accumulated amortization | (1,523) | (29) |
| Net assets under capital lease | $ 27,367 | $ 3,982 |

The following are the minimum lease payments to be made in each of the following years indicated for the capital lease in effect as of December 31, 2008 (in thousands):

| Fiscal Year | |
|---|---|
| 2009 through 2013 | $ 16,150 |
| Thereafter | 16,691 |
| Less: Interest | (5,184) |
| Net minimum lease payments under capital lease | 27,657 |
| Less: Current portion of net minimum lease payments | (3,189) |
| Long-term portion of net minimum lease payments | $ 24,468 |

**(8) Income Taxes**

The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The net tax basis in the Partnership's assets and liabilities is less than the reported amounts on the financial statements by approximately $437.2 million as of December 31, 2008. Effective January 1, 2007, the Partnership is subject to the margin tax enacted by the state of Texas on May 1, 2006.

The LIG entities the Partnership formed to acquire the stock of LIG Pipeline Company and its subsidiaries, are treated as taxable corporations for income tax purposes. The entity structure was formed to effect the matching of the tax cost to the Partnership of a step-up in the basis of the assets to fair market value with the recognition of benefits of the step-up by the Partnership. A deferred tax liability of $8.2 million was recorded at the acquisition date. The deferred tax liability represents future taxes payable on the difference between the fair value and tax basis of the assets acquired. The Partnership, through ownership of the LIG entities, generated a net operating loss of $4.8 million during 2005 as a result of a tax loss on a property sale of which $0.9 million was carried back to 2004, $1.9 million was utilized in 2006 and substantially all of the remaining $2.0 million was utilized in 2007.

The Partnership provides for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis that will reverse in future periods (in thousands).

**CROSSTEX ENERGY, L.P.**

**Notes to Consolidated Financial Statements — (Continued)**

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| Current tax provision (benefit) | $ 2,593 | $ 711 | $ (268) |
| Deferred tax provision (benefit) | 172 | 253 | 490 |
| | $ 2,765 | $ 964 | $ 222 |

A reconciliation of the provision for income taxes for the taxable corporation is as follows (in thousands):

| | | | |
|---|---|---|---|
| Federal income tax on taxable corporation at statutory rate (35%) | $ 197 | $ 206 | $ 206 |
| State income taxes, net | 2,568 | 758 | 16 |
| Income tax provision | $ 2,765 | $ 964 | $ 222 |

The principal component of the Partnership's net deferred tax liability is as follows (in thousands):

| | Years Ended December 31, | |
|---|---|---|
| | 2008 | 2007 |
| Deferred income tax assets: | | |
| Net operating loss carryforward — current | $ 41 | $ 4 |
| Net operating loss carryforward — long-term | — | 61 |
| Alternative minimum tax credit carryover — long-term | — | 99 |
| | $ 41 | $ 164 |
| Deferred income tax liabilities: | | |
| Property, plant, equipment, and intangible assets-current | $ (501) | $ (501) |
| Property, plant, equipment and intangible assets-long-term | (8,727) | (8,678) |
| | $ (9,228) | $ (9,179) |
| Net deferred tax liability | $ (9,187) | $ (9,015) |

A net current deferred tax liability of $0.5 million is included in other current liabilities.

The Partnership adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes,* on January 1, 2007. A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (in thousands):

| | |
|---|---|
| Balance as of December 31, 2007 | $ — |
| Increases related to prior year tax positions | 904 |
| Increases related to current year tax positions | 717 |
| Balance as of December 31, 2008 | $ 1,621 |

Unrecognized tax benefits of $1.6 million, if recognized, would affect the effective tax rate. We do not expect any material change in the balance of our unrecognized tax benefits over the next twelve months. In the event interest or penalties are incurred with respect to income tax matters, our policy will be to include such items in income tax expense. At December 31, 2008, tax years 2005 through 2008 remain subject to examination by the Internal Revenue Service and applicable states.

**(9) Partners' Capital**

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

On April 9, 2008, we issued 3,333,334 common units in a private offering at $30.00 per unit, which represented an approximate 7% discount from the market price. Crosstex Energy GP, L.P. made a general partner contribution of $2.0 million in connection with the issuance to maintain its 2% general partner interest.

On December 19, 2007, we issued 1,800,000 common units representing limited partner interests in the Partnership at a price of $33.28 per unit for net proceeds of $57.6 million. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $1.2 million in connection with the issuance to maintain its 2% general partner interest.

***(b) Conversion of Subordinated and Senior Subordinated Series C Units***

The subordination period for the Partnership's subordinated units ended and the remaining 4,668,000 subordinated units converted into common units representing limited partner interests of the Partnership effective February 16, 2008.

On June 29, 2006, the Partnership issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests of the Partnership in a private equity offering for net proceeds of approximately $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represented a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million in connection with this issuance to maintain its 2% general partner interest. The senior subordinated series C units converted into common units representing limited partner interests of the Partnership February 16, 2008. The senior subordinated series C units were not entitled to distributions of available cash from the Partnership until conversion. See Note 9(e) below for a discussion of the impact on earnings per unit resulting from the conversion of the senior subordinated series C units.

***(c) Senior Subordinated Series D Units***

On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests of the Partnership in a private offering. These senior subordinated series D units will convert into common units representing limited partner interests of the Partnership on March 23, 2009. Since the Partnership did not make distribution of available cash from operating surplus, as defined in the partnership agreement, of at least $0.62 per unit on each outstanding common unit for the quarter ending December 31, 2008, then each senior subordinated series D unit will convert into 1.05 common units.

***(d) Cash Distributions***

Unless restricted by the terms of our credit facility, 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 commencing with the quarter ended on March 31, 2003. Distributions will generally be made 98% to the common and subordinated unitholders and 2% to the general partner, subject to the payment of incentive distributions.

Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $30.8 million, $24.8 million and $20.4 million were earned by our general partner for the years ended December 31, 2008, 2007 and 2006, respectively. The Partnership paid annual per common unit distributions of $2.36, $2.28 and $2.13 for the years ended December 31, 2008, 2007 and 2006, respectively.

The Partnership decreased its fourth quarter distribution on its common units to $0.25 per unit which was paid February 13, 2009.

See Note 6 for a description of the Partnership's credit facilities which restrict the Partnership's ability to make future distributions.

***(e) Earnings per unit and anti-dilutive computations***

The Partnership's common units and subordinated units participate in earnings and distributions in the same manner for all historical periods and are therefore presented as a single class of common units for earnings per unit computations. The various series of senior subordinated units are also considered common securities, but because they do not participate in earnings or cash distributions during the subordination period are presented as separate classes of common equity. Each of the series of senior subordinated units were issued at a discount to the market price of the common units they are convertible into at the end of the subordination period. These discounts represent beneficial conversion features (BCFs) under EITF 98-5: *"Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios."* Under EITF 98-5 and related accounting guidance, a BCF represents a non-cash distribution that is treated in the same way as a cash distribution for earnings per unit computations. Since the conversion of all the series of senior subordinated units into common units are contingent (as described with the terms of such units) until the end of the subordination periods for each series of units, the BCF associated with each series of senior subordinated units is not reflected in earnings per unit until the end of such subordination periods when the criteria for conversion are met. Following is a summary of the BCFs attributable to the senior subordinated units outstanding during 2006, 2007 and 2008 (in thousands):

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

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Limited partners' interest in net income (loss) | $ (15,644) | $ (5,363) | $ (20,647) |
| Distributed earnings allocated to: | | | |
| Common units(1) | $ 97,251 | $ 61,760 | $ 55,827 |
| Senior subordinated series A units(2) | — | — | 7,941 |
| Senior subordinated series C units(2) | 121,112 | — | — |
| Total distributed earnings | $ 218,363 | $ 61,760 | $ 63,768 |
| Undistributed loss allocated to: | | | |
| Common units(3) | $ (234,007) | $ (67,123) | $ (84,415) |
| Senior subordinated series A units | — | — | — |
| Senior subordinated series C units | — | — | — |
| Total undistributed earnings (loss) | $ (234,007) | $ (67,123) | $ (84,415) |
| Net income (loss) allocated to: | | | |
| Common units | $ (136,756) | $ (5,363) | $ (28,588) |
| Senior subordinated series A units | — | — | 7,941 |
| Senior subordinated series C units | 121,112 | — | — |
| Total limited partners' interest in net income (loss) | (15,644) | $ (5,363) | $ (20,647) |
| Income from discontinued operations: | | | |
| Common units(4) | $ 54,446 | $ 6,352 | $ 7,170 |
| Senior subordinated series A, C and D units | — | — | — |
| Total income from discontinued operation | $ 54,446 | $ 6,352 | $ 7,170 |

**CROSSTEX ENERGY, L.P.**

**Notes to Consolidated Financial Statements — (Continued)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Cumulative effect of the change in accounting principle: | | | |
| Common units | $ — | $ — | $ 689 |
| Senior subordinated A, C and D units | — | — | — |
| Total cumulative effect of the change in accounting principle | $ — | $ — | $ 689 |
| Basic and diluted net income (loss) per unit from continuing operations: | | | |
| Basic and diluted common units | $ (4.52) | $ (0.44) | $ (1.39) |
| Senior subordinated series A units | $ — | $ — | $ 5.31 |
| Senior subordinated series C units | $ 9.44 | $ — | $ — |
| Senior subordinated series D units | $ — | $ — | $ — |
| Basic and diluted net income (loss) on discontinued operations: | | | |
| Basic and diluted common units | $ 1.29 | $ 0.24 | $ 0.27 |
| Senior subordinated series A, C and D units | $ — | $ — | $ — |
| Basic cumulative effect of change in accounting principle per unit: | | | |
| Common units | $ — | $ — | $ 0.03 |
| Senior subordinated A, C and D units | $ — | $ — | $ — |
| Total basic and diluted net income (loss) per unit: | | | |
| Basic and diluted common units | $ (3.23) | $ (0.20) | $ (1.09) |
| Senior subordinated series A units | $ — | $ — | $ 5.31 |
| Senior subordinated series C units | $ 9.44 | $ — | $ — |
| Senior subordinated series D units | $ — | $ — | $ — |

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

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

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

(4) Represents 98.0% for the limited partners' interest in discontinued operations.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2008, 2007, and 2006 (in thousands):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Weighted average limited partner common units outstanding | 42,330 | 26,753 | 26,337 |
| Weighted average senior subordinated series A units | — | — | 1,495 |
| Weighted average senior subordinated series C units | 12,830 | — | — |

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented. All common unit equivalents were antidilutive for the years ended December 31, 2008, 2007 and 2006 because the limited partners were allocated net losses in the periods.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note 9(d). In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to CEI stock options and restricted stock all to the general partner to match the related general partner contribution. Therefore, the general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related

stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units and the common units. The net income allocated to the general partner is as follows (in thousands):

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Income allocation for incentive distributions | $ 30,772 | $ 24,802 | $ 20,422 |
| Stock-based compensation attributable to CEI's stock options and restricted shares | (4,665) | (5,441) | (3,545) |
| 2% general partner interest in net income (loss) | 308 | (109) | (421) |
| General partner share of net income | $ 26,415 | $ 19,252 | $ 16,456 |

**(10) Retirement Plans**

The Partnership sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The plan allows for contributions to be made at each compensation calculation period based on the annual discretionary contribution rate. Contributions of $3.4 million, $1.6 million and $1.1 million were made to the plan for the years ended December 31, 2008, 2007 and 2006, respectively.

**(11) Employee Incentive Plans**

***(a) Long-Term Incentive Plan***

The Partnership's managing general partner has a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 4,800,000 common unit options and restricted units. The plan is administered by the compensation committee of the managing general partner's board of directors. The units issued upon exercise or vesting are newly issued units.

***(b) Restricted Units***

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the restricted units will become exercisable upon a change of control of the Partnership, its general partner or its general partner's general partner.

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted in 2006, 2007 and 2008 generally cliff vest after three years of service.

**CROSSTEX ENERGY, L.P.**

**Notes to Consolidated Financial Statements — (Continued)**

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 year ended December 31, 2008 is provided below:

| Crosstex Energy, L.P. Restricted Units: | Number of Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested, beginning of period | 504,518 | $ 34.29 |
| Granted | 432,354 | 29.60 |
| Vested* | (204,033) | 33.40 |
| Forfeited | (34,273) | 29.69 |
| Reduced estimated performance units | (154,499) | 31.66 |
| Non-vested, end of period | 544,067 | $ 31.90 |
| Aggregate intrinsic value, end of period (in thousands) | $ 2,378 | |

* Vested units include 51,214 units withheld for payroll taxes paid on behalf of employees.

The Partnership's executive officers were granted restricted units during 2008 and 2007, the number of which may increase or decrease based on the accomplishment of certain performance targets based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over a three-year period). The minimum number of restricted units for all executives of 52,795 and 14,319 for 2008 and 2007, respectively, are included in the non-vested end of period units line in the table above. Target performance grants were previously included in the restricted units granted and were included in share-based compensation as it appeared probable that target thresholds would be achieved. However, during the last half of 2008, the Partnership's assets were negatively impacted by hurricanes Gustav and Ike. During this same period, the Partnership has also been negatively impacted by the declines in natural gas and NGL prices coupled with the global economic decline and tightening of capital markets. The impact of these events was significant enough to make the achievement of target performance goals less than probable. Therefore, an expense of $0.7 million previously recorded for target performance-based restricted units has been reversed and is shown as a reduction to stock-based compensation expense and a reduction in the number of estimated performance units outstanding of 154,499 units in the year ended December 31, 2008. All performance-based awards greater than the minimum performance grant levels will be subject to reevaluation and adjustment until the restricted units vest. The performance-based restricted units are included in the current share-based compensation calculations as required by SFAS No. 123(R) when it is deemed probable of achieving the performance criteria.

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 years ended December 31, 2008 and 2007 are provided below (in thousands):

| Crosstex Energy, L.P. Restricted Units: | Years Ended December 31, 2008 | 2007 |
|---|---|---|
| Aggregate intrinsic value of units vested | $ 5,907 | $ 1,342 |
| Fair value of units vested | $ 6,815 | $ 888 |

As of December 31, 2008, there was $7.8 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.5 years.

*(c) Unit Options*

Unit options will have an exercise price that is not less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, its general partner or its general partner's general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior to estimate expected forfeiture rates. The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant. The Partnership used the simplified method to calculate the expected term.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant. The unit options granted in 2008, 2007 and 2006 generally vest based on 3 years of service (one-third after each year of service). The following weighted average assumptions were used for the Black-Scholes option-pricing model for grants in 2008, 2007 and 2006:

| | Years Ended December 31, | | |
|---|---|---|---|
| **Crosstex Energy, L.P. Unit Options Granted:** | **2008** | **2007** | **2006** |
| Weighted average distribution yield | 7.15% | 5.75% | 5.5% |
| Weighted average expected volatility | 30.0% | 32.0% | 33.0% |
| Weighted average risk free interest rate | 1.81% | 4.39% | 4.80% |
| Weighted average expected life | 6 years | 6 years | 6 years |
| Weighted average contractual life | 10 years | 10 years | 10 years |
| Weighted average of fair value of unit options granted | $ 3.48 | $ 6.73 | $ 7.45 |

A summary of the unit option activity for the years ended December 31, 2008, 2007 and 2006 is provided below:

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2008 | | 2007 | | 2006 | |
| | Number of Units | Weighted Average Exercise Price | Number of Units | Weighted Average Exercise Price | Number of Units | Weighted Average Exercise Price |
| Outstanding, beginning of period | 1,107,309 | $ 29.65 | 926,156 | $ 25.70 | 1,039,832 | $ 18.88 |
| Granted(b) | 402,185 | 31.58 | 347,599 | 37.29 | 286,403 | 34.62 |
| Exercised | (56,678) | 14.16 | (90,032) | 18.20 | (304,936) | 11.19 |
| Forfeited | (90,208) | 31.29 | (67,688) | 29.84 | (95,143) | 24.56 |
| Expired | (58,414) | 32.93 | (8,726) | 31.60 | — | — |
| Outstanding, end of period | 1,304,194 | $ 30.64 | 1,107,309 | $ 29.65 | 926,156 | $ 25.70 |
| Options exercisable at end of period | 540,782 | $ 29.12 | 281,973 | $ 28.05 | 121,131 | $ 23.58 |
| Weighted average contractual term (years) end of period: | | | | | | |
| Options outstanding | 7.4 | — | 7.6 | — | 7.8 | — |
| Options exercisable | 6.5 | — | 7.1 | — | 7.5 | — |
| Aggregate intrinsic value end of period (in thousands): | | | | | | |
| Options outstanding | $ (a) | — | $ 4,681 | — | $ 13,107 | — |
| Options exercisable | $ (a) | — | $ 1,322 | — | $ 1,970 | — |

(a) Exercise price on all outstanding options exceed current market price.

(b) No options were granted with an exercise price less than or equal to market value at grant during 2008, 2007 and 2006.

A summary of the unit options intrinsic value (market value in excess of exercise price at date of exercise) exercised and fair value of units vested (value per Black-Scholes option pricing model at date of grant) during the years ended December 31, 2008 and 2007 are provided below (in thousands):

| | Years Ended December 31, | |
|---|---|---|
| **Crosstex Energy, L.P. Unit Options:** | **2008** | **2007** |
| Intrinsic value of units options exercised | $746 | $1,675 |
| Fair value of units vested | $279 | $ 197 |

As of December 31, 2008, there was $1.6 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 1.5 years.

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

The Crosstex Energy, Inc. long-term incentive plan provides for the award of stock options and restricted stock (collectively, "Awards") for up to 4,590,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2009, approximately 626,000 shares remained available under the long-term incentive plan for future issuance to participants. A participant may not receive in any calendar year options relating to more than 100,000 shares of common stock. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Shares of common stock underlying Awards that are forfeited, terminated or expire unexercised become immediately available for additional Awards under the long-term incentive plan.

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. CEI's restricted stock granted in 2006, 2007 and 2008 generally cliff vest after three years of service. A summary of the restricted stock activity which includes officers and employees of the Partnership and directors of CEI for the year ended December 31, 2008, is provided below:

| **Crosstex Energy, Inc. Restricted Shares:** | **Number of Shares** | **Weighted Average Grant-Date Fair Value** |
|---|---|---|
| Non-vested, beginning of period | 860,275 | $ 21.16 |
| Granted | 361,796 | 32.62 |
| Vested* | (401,004) | 18.41 |
| Forfeited | (63,716) | 21.86 |
| Reduced estimated performance shares | (153,038) | 32.10 |
| Non-vested, end of period | 604,313 | $ 27.62 |
| Aggregate intrinsic value, end of period (in thousands) | $ 2,357 | |

* Vested shares include 116,118 shares withheld for payroll taxes paid on behalf of employees.

The Partnership's executive officers were granted restricted shares during 2008 and 2007, the number of which may increase or decrease based on the accomplishment of certain performance targets based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over a three-year period). The minimum number of restricted shares for all executives of 50,090 and 16,536 for 2008 and

2007, respectively, are included in the non-vested, end of period shares line in the table above. Target performance grants were previously included in the restricted units granted and were included in share-based compensation as it appeared probable that target thresholds would be achieved. However, during the last half of 2008, the Partnership's assets were negatively impacted by hurricanes Gustav and Ike. During this same period, the Partnership has also been negatively impacted by the declines in natural gas and NGL prices coupled with the global economic decline and tightening of capital markets. The impact of these events was significant enough to make the achievement of target performance goals less than probable. Therefore, an expense of $0.7 million previously recorded for target performance-based restricted shares has been retroactively reversed and is shown as a reduction to stock-based compensation expense and a reduction in the number of estimated performance shares outstanding by 153,038 shares in the year ended December 31, 2008. All performance-based awards greater than the minimum performance grant levels will be subject to reevaluation and adjustment until the restricted shares vest. The performance-based restricted shares are included in the current share-based compensation calculations as required by SFAS No. 123(R) when it is deemed probable of achieving the performance criteria.

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 years ended December 31, 2008 and 2007 are provided below (in thousands):

| | Years Ended December 31, | |
|---|---|---|
| **Crosstex Energy, Inc. Restricted Shares:** | **2008** | **2007** |
| Aggregate intrinsic value of shares vested | $13,493 | $3,067 |
| Fair value of shares vested | $ 7,382 | $1,275 |

Restricted shares in CEI totaling 244,578 and 186,840 were issued to officers and employees of the Partnership with a weighted-average grant-date fair value of $29.58 and $25.05 per share in 2007 and 2006, respectively. As of December 31, 2008 and 2007, there was $7.2 million and $7.0 million, respectively, of unrecognized compensation costs related to CEI restricted shares for officers and employees. The cost is expected to be recognized over a weighted average period of 2.4 years.

***CEI Stock Options***

No CEI stock options were granted to any officers or employees of the Partnership during 2008, 2007 and 2006.

A summary of the stock option activity includes officers and employees of the Partnership and directors of CEI for the years ended December 31, 2008, 2007 and 2006 is provided below:

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2008 | | 2007 | | 2006 | |
| | Number of Shares | Weighted Average Exercise Price | Number of Shares | Weighted Average Exercise Price | Number of Shares(a) | Weighted Average Exercise Price(a) |
| Outstanding, beginning of period | 105,000 | $ 8.45 | 120,000 | $ 8.21 | 159,933 | $ 9.53 |
| Granted | — | — | — | — | — | — |
| Cancelled | — | — | — | — | — | — |
| Exercised | (37,500) | 6.50 | (15,000) | 6.50 | (9,933) | 12.58 |
| Forfeited | — | — | — | — | (30,000) | 13.83 |
| Outstanding, end of period | 67,500 | $ 9.54 | 105,000 | $ 8.45 | 120,000 | $ 8.21 |
| Options exercisable at end of period | 22,500 | $ 11.05 | 37,500 | $ 7.87 | — | — |

(a) Adjusted to reflect three-for-one stock split.

The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of December 31, 2008:

| | | |
|---|---|---|
| Outstanding stock options (15,000 exercisable) (post stock split) | | 30,000 |
| Weighted average exercise price (post stock split) | $ | 13.33 |
| Aggregate intrinsic value | $ | — |
| Weighted average remaining contractual term | | 5.9 years |

A summary of the share options intrinsic value (market value in excess of exercise price at date of exercise) exercised and fair value of units vested (value per Black-Scholes option pricing model at date of grant) during the years ended December 31, 2008 and 2007 is provided below (in thousands):

| | Years Ended December 31, | |
|---|---|---|
| **Crosstex Energy, Inc. Stock Options:** | **2008** | **2007** |
| Intrinsic value of units options exercised | $ 1,089 | $ 366 |
| Fair value of units vested | $ 38 | $ 66 |

No stock options were granted, cancelled, exercised or forfeited by officers and employees of the Partnership during the years ended December 31, 2008, 2007 and 2006.

As of December 31, 2008, there was $15,449 of unrecognized compensation costs related to non-vested CEI stock options. The cost is expected to be recognized over a weighted average period of 0.8 years.

**(12) 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).

| | December 31, 2008 | | December 31, 2007 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Cash and cash equivalents | $ 1,636 | $ 1,636 | $ 142 | $ 142 |
| Trade accounts receivable and accrued revenues | 341,853 | 341,853 | 489,889 | 489,889 |
| Fair value of derivative assets | 31,794 | 31,794 | 9,926 | 9,926 |
| Note receivable | 375 | 375 | 1,026 | 1,026 |
| Accounts payable, drafts payable and accrued gas purchases | 315,622 | 315,622 | 469,951 | 469,951 |
| Current portion of long-term debt | 9,412 | 9,412 | 9,412 | 9,412 |
| Long-term debt | 1,254,294 | 1,148,939 | 1,213,706 | 1,225,087 |
| Fair value of derivative liabilities | 51,281 | 51,281 | 30,492 | 30,492 |

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 carrying value for the note receivable approximates the fair value because this note earns interest based on the current prime rate.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $784.0 million and $734.0 million as of December 31, 2008 and 2007, respectively, which accrues interest under a floating interest rate structure. Accordingly, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2008, the Partnership also had borrowings totaling $479.7 million under senior secured notes with a weighted average interest rate of 8.0%. The fair value of

these borrowings as of December 31, 2008 and 2007 were adjusted to reflect current market interest rate for such borrowings as of December 31, 2008 and 2007, respectively.

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.

**(13) Derivatives**

***Interest Rate Swaps***

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk.

The Partnership entered into eight interest rate swaps prior to September 2008 as shown below:

| Trade Date | Term | From | To | Rate | Notional Amounts (In thousands) |
|---|---|---|---|---|---|
| November 14, 2006 | 4 years | November 28, 2006 | November 30, 2010 | 4.3800% | $ 50,000 |
| March 13, 2007 | 4 years | March 30, 2007 | March 31, 2011 | 4.3950% | 50,000 |
| July 30, 2007 | 4 years | August 30, 2007 | August 30, 2011 | 4.6850% | 100,000 |
| August 6, 2007 | 4 years | August 30, 2007 | August 31, 2011 | 4.6150% | 50,000 |
| August 9, 2007 | 3 years | November 30, 2007 | November 30, 2010 | 4.4350% | 50,000 |
| August 16, 2007* | 4 years | October 31, 2007 | October 31, 2011 | 4.4875% | 100,000 |
| September 5, 2007 | 4 years | September 28, 2007 | September 28, 2011 | 4.4900% | 50,000 |
| January 22, 2008 | 1 year | January 31, 2008 | January 31, 2009 | 2.8300% | 100,000 |
| | | | | | $ 550,000 |

* Amended swap is a combination of two swaps that each had a notional amount of $50.0 million with the same original term.

Each swap fixes the three month LIBOR rate, prior to credit margin, at the indicated rates for the specified amounts of related debt outstanding over the term of each swap agreement. In January 2008, the Partnership amended existing swaps with the counterparties in order to reduce the fixed rates and extend the terms of the existing swaps by one year. The Partnership also entered into one new swap in January 2008.

The Partnership had previously elected to designate all interest rate swaps (except the November 2006 swap) as cash flow hedges for FAS 133 accounting treatment. Accordingly, unrealized gains and losses relating to the designated interest rate swaps were recorded in accumulated other comprehensive income. Immediately prior to the January 2008 amendments, these swaps were de-designated as cash flow hedges. The unrealized loss in accumulated other comprehensive income of $17.0 million at the de-designation dates is being reclassified to earnings over the remaining original terms of the swaps using the effective interest method. The related loss reclassified to earnings and included in (gain) loss on derivatives during the year ended December 31, 2008 is $6.4 million.

The Partnership elected not to designate any of the amended swaps or the new swap entered into in January 2008 as cash flow hedges for FAS 133 treatment. Accordingly, unrealized gains and losses are recorded through the consolidated statement of operations in (gain) loss on derivatives over the period hedged.

In September 2008, the Partnership entered into four additional interest rate swaps. The effect of the new interest rate swaps was to convert the floating rate portion of the original swaps on $450.0 million (all swaps except the January 22, 2008 swap that expires January 31, 2009) from three month LIBOR to one month LIBOR. The Partnership received a cash settlement in September of $1.4 million which represented the present value of the basis

point differential between one month LIBOR and three month LIBOR. The $1.4 million was recorded in the consolidated statement of operations in (gain) loss on derivatives.

The table below aligns the new swap which receives one month LIBOR and pays three month LIBOR with the original interest rate swaps.

| Original Swap Trade Date | New Trade Date | From | To | Notional Amounts (In thousands) |
|---|---|---|---|---|
| March 13, 2007 | September 12, 2008 | September 30, 2008 | March 31, 2011 | $ 50,000 |
| September 5, 2007 | September 12, 2008 | September 30, 2008 | September 28, 2011 | 50,000 |
| August 16, 2007 | September 12, 2008 | October 30, 2008 | October 31, 2011 | 100,000 |
| November 14, 2006 | September 12, 2008 | November 28, 2008 | November 30, 2010 | 50,000 |
| August 9, 2007 | September 12, 2008 | November 28, 2008 | November 30, 2010 | 50,000 |
| July 30, 2007 | September 12, 2008 | November 28, 2008 | August 30, 2011 | 100,000 |
| August 6, 2007 | September 23, 2008 | November 28, 2008 | August 30, 2011 | 50,000 |
| | | | | $ 450,000 |

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

| | Years Ended December 31, 2008 | 2007 |
|---|---|---|
| Change in fair value of derivatives that do not qualify for hedge accounting | $ (22,105) | $ (1,185) |
| Realized gains on derivatives | (4,608) | 707 |
| Ineffective portion of derivatives qualifying for hedge accounting | — | — |
| | $ (26,713) | $ (478) |

No comparison is listed for 2006 because the first interest rate swaps were entered into in November 2006 and therefore had no material operational impact prior to 2007.

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

| | Years Ended December 31, 2008 | 2007 |
|---|---|---|
| Fair value of derivative assets — current | $ 149 | $ 68 |
| Fair value of derivative assets — long-term | — | — |
| Fair value of derivative liabilities — current | (17,217) | (3,266) |
| Fair value of derivative liabilities — long-term | (18,391) | (8,057) |
| Net fair value of interest rate swaps | $ (35,459) | $ (11,255) |

***Commodity Swaps***

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

**CROSSTEX ENERGY, L.P.**

**Notes to Consolidated Financial Statements — (Continued)**

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

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Change in fair value of derivatives that do not qualify for hedge accounting | $ (246) | $ 1,197 | $ 713 |
| Realized (gains) losses on derivatives | (11,889) | (7,918) | (2,238) |
| Ineffective portion of derivatives qualifying for hedge accounting | (68) | 93 | (66) |
| | $ (12,203) | $ (6,628) | $ (1,591) |

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

| | Years Ended December 31, | |
|---|---|---|
| | 2008 | 2007 |
| Fair value of derivative assets — current | $ 27,017 | $ 8,521 |
| Fair value of derivative assets — long term | 4,628 | 1,337 |
| Fair value of derivative liabilities — current | (11,289) | (17,800) |
| Fair value of derivative liabilities — long term | (4,384) | (1,369) |
| Net fair value of commodity swaps | $ 15,972 | $ (9,311) |

Set forth below is the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at December 31, 2008 (all gas volumes are expressed in MMBtu's and liquids are expressed in gallons). The remaining terms of the contracts extend no later than June 2010 for derivatives, except for certain basis swaps that extend to March 2012. The Partnership's counterparties to derivative contracts include BP Corporation, Total Gas & Power, Fortis, Morgan Stanley, J. Aron & Co., a subsidiary of Goldman Sachs and Sempra Energy. 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.

**CROSSTEX ENERGY, L.P.**

**Notes to Consolidated Financial Statements — (Continued)**

| Transaction Type | December 31, 2008 Volume | Fair Value |
|---|---|---|
| | (In thousands) | |
| *Cash Flow Hedges:* | | |
| Natural gas swaps (short contracts) (MMBtu's) | (600) | $ 1,136 |
| Liquids swaps (short contracts) (gallons) | (16,026) | 12,578 |
| Total swaps designated as cash flow hedges | | $ 13,714 |
| *Mark to Market Derivatives:** | | |
| Swing swaps (long contracts) | 2,155 | $ 10 |
| Physical offsets to swing swap transactions (short contracts) | (2,155) | — |
| Swing swaps (short contracts) | (397) | (3) |
| Physical offsets to swing swap transactions (long contracts) | 397 | — |
| Basis swaps (long contracts) | 82,681 | 7,464 |
| Physical offsets to basis swap transactions (short contracts) | (1,550) | 9,072 |
| Basis swaps (short contracts) | (78,025) | (6,175) |
| Physical offsets to basis swap transactions (long contracts) | 1,771 | (9,067) |
| Third-party on-system financial swaps (long contracts) | 2,300 | (8,065) |
| Physical offsets to third-party on-system transactions (short contracts) | (2,283) | 8,157 |
| Third-party on-system financial swaps (short contracts) | (172) | 2 |
| Physical offsets to third-party on-system transactions (long contracts) | 155 | 89 |
| Storage swap transactions (long contracts) | 158 | (23) |
| Storage swap transactions (short contracts) | (353) | 797 |
| Total mark to market derivatives | | $ 2,258 |

* All are gas contracts, volume in MMBtu's

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

***Impact of Cash Flow Hedges***

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

| Increase (Decrease) in Midstream Revenue | Years Ended December 31, 2008 | 2007 | 2006 |
|---|---|---|---|
| Natural gas | $ 63 | $ 5,533 | $ 5,886 |
| Liquids | (10,402) | (4,066) | 1,504 |
| | $ (10,339) | $ 1,467 | $ 7,390 |

*Natural Gas*

As of December 31, 2008 an unrealized derivative fair value net gain of $1.1 million related to cash flow hedges of gas price risk was recorded in accumulated other comprehensive income (loss). Of this net amount, a

$1.1 million gain is expected to be reclassified into earnings through December 2009. The actual reclassification to earnings will be based on mark to market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

The settlement of cash flow hedge contracts related to January 2009 gas production increased gas revenue by approximately $0.1 million.

*Liquids*

As of December 31, 2008, an unrealized derivative fair value net gain of $12.6 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this amount, a $12.6 million gain is expected to be reclassified into earnings through December 2009. The actual reclassification to earnings will be based on mark to market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

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

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

| | Maturity Periods | | | |
|---|---|---|---|---|
| | Less Than One Year | One to Two Years | More Than Two Years | Total Fair Value |
| December 31, 2008 | $ 2,014 | $ 181 | $ 63 | $ 2,258 |

**(14) Fair Value Measurements**

In September 2006, the FASB issued SFAS No. 157, *"Fair Value Measurements"* (SFAS 157). SFAS 157 introduces a framework for measuring fair value and expands required disclosure about fair value measurements of assets and liabilities. SFAS 157 for financial assets and liabilities is effective for fiscal years beginning after November 15, 2007. The Partnership has adopted the standard for those assets and liabilities as of January 1, 2008 and the impact of adoption was not significant.

Fair value 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.

SFAS 157 establishes 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 swaps and interest rate swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. The Partnership determines the value of interest rate swap contracts by utilizing inputs and quotes from the

counterparties to these contracts. The reasonableness of these inputs and quotes is verified by comparing similar inputs and quotes from other counterparties as of each date for which financial statements are prepared.

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

| | Total | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| Interest rate swaps* | $ (35,459) | — | $ (35,459) | — |
| Commodity swaps* | 15,972 | — | 15,972 | — |
| Total | $ (19,487) | — | $ (19,487) | — |

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income (loss) at each measurement date. Accumulated other comprehensive income also includes the unrealized losses on interest rate swaps of $17.0 million recorded prior to de-designation in January 2008, of which $6.4 million has been amortized to earnings through December 2008.

**(15) Transactions with Related Parties**

***(a) Plants Transferred from Crosstex Energy Inc.***

During 2008 CEI transferred two inactive processing plants to the Partnership at net book value for a cash price of $0.4 million which represented the fair value of the plants.

***(b) General and Administrative Expenses***

CEI paid the Partnership $0.7 million, $0.6 million and $0.5 million during the years ended December 31, 2008, 2007 and 2006, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI.

**(16) Commitments and Contingencies**

***(a) Leases — Lessee***

The Partnership has operating leases for office space, office and field equipment and the Eunice plant. The Eunice plant operating lease acquired with the south Louisiana processing assets provides for annual lease payments of $12.2 million with a lease term extending to November 2012. At the end of the lease term the Partnership has the option to purchase the plant for $66.3 million or to renew the lease for up to an additional 9.5 years at 50% of the lease payments under the current lease.

The following table summarizes the Partnership's remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in millions):

| | |
|---|---|
| 2009 | $ 28.4 |
| 2010 | 19.0 |
| 2011 | 17.9 |
| 2012 | 16.4 |
| 2013 | 3.1 |
| Thereafter | 3.7 |
| | $ 88.5 |

Operating lease rental expense in the years ended December 31, 2008, 2007 and 2006, was approximately $43.8 million, $31.7 million, and $23.8 million, respectively.

***(b) Leases — Lessor***

During 2008, the Partnership leased approximately 162 of its treating plants, most of which the Partnership operates, and 33 of its dew point control plants to customers under operating leases. The initial terms on these leases are generally 12 months, at which time the leases revert to 30-day cancelable leases. As of December 31, 2008, the Partnership only had 31 treating plants under 36 operating leases with remaining non-cancelable lease terms in excess of one year. The future minimum lease rentals are $16.3 million and $5.4 million for the years ended December 31, 2009 and 2010, respectively. These leased treating plants have a cost of $25.4 million and accumulated depreciation of $4.9 million as of December 31, 2008.

***(c) Employment Agreements***

Certain members of management of the Partnership are parties to employment contacts with the general partner. The employment agreements provide those senior managers with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

***(d) Environmental Issues***

The Partnership acquired the south Louisiana processing assets from the El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has an active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the oversight of the Louisiana Department of Environmental Quality (LDEQ) and is being conducted under the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that is expected to significantly reduce the cost of and timing for remediation projects. As of December 31, 2008, we had incurred approximately $0.5 million in remediation costs. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

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

The Partnership acquired assets from Duke Energy Field Services, or DEFS, in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of the Conroe site. Moreover, DEFS has entered into an agreement with a third party company pursuant to which the remediation costs associated with the Conroe site have been assumed by

this third party company that specializes in remediation work. The Partnership does not expect to incur any material environmental liability associated with the Conroe site; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations.

***(e) 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.

On November 15, 2007, Crosstex CCNG Processing Ltd. ("Crosstex Processing"), the Partnership's wholly-owned subsidiary, received a demand letter from Denbury Onshore, LLC ("Denbury"), asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. On April 15, 2008, the parties mediated the matter unsuccessfully. On December 4, 2008, Denbury initiated formal arbitration proceedings against Crosstex Processing, Crosstex Energy Services, L.P., Crosstex North Texas Gathering, L.P., and Crosstex Gulf Coast Marketing, Ltd., seeking $11.4 million and additional unspecified damages. On December 23, 2008, Crosstex Processing filed an answer denying Denbury's allegations and a counterclaim seeking a declaratory judgment that its processing plant is uneconomic under the Processing Contract. Crosstex Energy, Crosstex Marketing, and Crosstex Gathering also filed an answer denying Denbury's allegations and asserting that they are improper parties as Denbury's claim is for breach of the Processing Contract and none of these entities is a party to that agreement. Crosstex Gathering also filed a counterclaim seeking approximately $40.0 million in damages for the value of the NGLs it is entitled to under its Gas Gathering Agreement with Denbury. Once the three-person arbitration panel has been named and cleared conflicts, the arbitration panel will hold a preliminary conference with the parties to set a date for the final hearing and other case deadlines and to establish discovery limits. Although it is not possible to predict with certainty the ultimate outcome of this matter, the Partnership does not believe this will have a material adverse effect on its consolidated results of operations or financial position.

The Partnership (or its subsidiaries) is defending eleven lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems in north Texas. 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. At this time, five cases are set for trial in 2009. The remaining cases have not yet been set for trial. Discovery is underway. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed the Partnership approximately $6.2 million, including approximately $3.9 million for June 2008 sales and approximately $2.2 million for July 2008 sales. The Partnership believes the July sales of $2.2 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to Crosstex for an administrative claim in the amount of $2.2 but the allowance of the administrative claim status is still subject to approval of the bankruptcy court in accordance with the administrative claim allowance procedures order in the case. The Partnership evaluated these receivables for collectibility and provided a valuation allowance of $3.1 million during the year ended December 31, 2008.

**(17) Segment Information**

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the south Louisiana processing and liquids assets, the processing and transmission assets located in north and south Texas, the LIG

pipelines and processing plants located in Louisiana, the Mississippi System, and various other small systems. Also included in the Midstream division are the Partnership's energy trading operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or through fixed monthly payments.

The accounting policies of the operating segments are the same as those described in Note 2 of the Notes to Consolidated Financial Statements. The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt financing costs.

Summarized financial information concerning the Partnership's reportable segments is shown in the following table. There are no other significant non-cash items.

| | Midstream | Treating | Corporate | Totals |
|---|---|---|---|---|
| | | (In thousands) | | |
| **Year ended December 31, 2008:** | | | | |
| Sales to external customers | $ 4,838,747 | $ 64,953 | $ — | $ 4,903,700 |
| Sales to affiliates | 16,155 | 7,367 | (23,522) | — |
| Profit on energy trading activities | 3,349 | — | — | 3,349 |
| Purchased gas | (4,487,463) | (14,579) | 16,155 | (4,485,887) |
| Operating expenses | (148,898) | (27,517) | 7,367 | (169,048) |
| Segment profit | $ 221,890 | $ 30,224 | $ — | $ 252,114 |
| Gain (loss) on derivatives | $ 12,203 | $ — | $ — | $ 12,203 |
| Impairments | $ 20,365 | $ 1,063 | $ 9,008 | $ 30,436 |
| Depreciation and amortization | $ (112,767) | $ (12,484) | $ (5,936) | $ (131,187) |
| Capital expenditures (excluding acquisitions) | $ 224,032 | $ 32,299 | $ 11,431 | $ 267,762 |
| Identifiable assets | $ 2,303,679 | $ 200,114 | $ 29,473 | $ 2,533,266 |
| **Year ended December 31, 2007:** | | | | |
| Sales to external customers | $ 3,791,316 | $ 53,682 | $ — | $ 3,844,998 |
| Sales to affiliates | 9,441 | 4,944 | (14,385) | — |
| Profit on energy trading activities | 4,090 | — | — | 4,090 |
| Purchased gas | (3,478,365) | (7,892) | 9,441 | (3,476,816) |
| Operating expenses | (109,875) | (20,218) | 4,944 | (125,149) |
| Segment profit | $ 216,607 | $ 30,516 | $ — | $ 247,123 |
| Gain (loss) on derivatives | $ 6,628 | $ — | $ — | $ 6,628 |
| Impairments | $ — | $ — | $ — | $ — |
| Depreciation and amortization | $ (89,575) | $ (12,327) | $ (4,737) | $ (106,639) |
| Capital expenditures (excluding acquisitions) | $ 371,120 | $ 25,085 | $ 5,192 | $ 401,397 |
| Identifiable assets | $ 2,337,081 | $ 214,481 | $ 41,312 | $ 2,592,874 |

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

| | Midstream | Treating | Corporate | Totals |
|---|---|---|---|---|
| | | (In thousands) | | |
| **Year ended December 31, 2006:** | | | | |
| Sales to external customers | $ 3,075,481 | $ 52,095 | $ — | $ 3,127,576 |
| Sales to affiliates | 10,520 | 2,412 | (12,932) | — |
| Profit on energy trading activities | 2,510 | — | — | 2,510 |
| Purchased gas | (2,870,335) | (9,463) | 10,520 | (2,869,278) |
| Operating expenses | (83,355) | (17,851) | 2,412 | (98,794) |
| Segment profit | $ 134,821 | $ 27,193 | $ — | $ 162,014 |
| Gain (loss) on derivatives | $ 1,591 | $ — | $ — | $ 1,591 |
| Impairments | $ — | $ — | $ — | $ — |
| Depreciation and amortization | $ (63,348) | $ (13,587) | $ (3,583) | $ (80,518) |
| Capital expenditures (excluding acquisitions) | $ 294,597 | $ 31,463 | $ 8,184 | $ 334,244 |
| Identifiable assets | $ 1,960,213 | $ 203,528 | $ 30,733 | $ 2,194,474 |

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Segment profits | $ 252,114 | $ 247,123 | $ 162,014 |
| General and administrative expenses | (71,005) | (61,528) | (45,694) |
| Gain on derivatives | 12,203 | 6,628 | 1,591 |
| Gain on sale of property | 1,519 | 1,667 | 2,108 |
| Depreciation and amortization | (131,187) | (106,639) | (80,518) |
| Impairments | (30,436) | — | — |
| Operating income | $ 33,208 | $ 87,251 | $ 39,501 |

**(18) Quarterly Financial Data (Unaudited)**

Summarized unaudited quarterly financial data is presented below.

| | First | Second | Third | Fourth | Total |
|---|---|---|---|---|---|
| | | (In thousands, except per unit data) | | | |
| 2008 | | | | | |
| Revenues | $ 1,266,720 | $ 1,540,608 | $ 1,330,610 | $ 769,111 | $ 4,907,049 |
| Operating income (loss) | 23,791 | 25,184 | 16,546 | (32,313) | 33,208 |
| Income from discontinued operations | 1,511 | 1,472 | 1,338 | 51,236 | 55,557 |
| Net income (loss) | 3,711 | 21,742 | (5,243) | (9,439) | 10,771 |
| Earnings (loss) per limited partner unit-basic | $ (3.66) | $ 0.23 | $ (0.25) | $ (0.19) | $ (3.23) |
| Earnings (loss) per limited partner unit-diluted | $ (3.66) | $ 0.21 | $ (0.25) | $ (0.19) | $ (3.23) |
| Basic and diluted senior subordinated A unit | $ — | $ — | $ — | $ — | $ — |
| Basic and diluted senior subordinated C unit | $ 9.44 | $ — | $ — | $ — | $ 9.44 |

**CROSSTEX ENERGY, L.P.**

**Notes to Consolidated Financial Statements — (Continued)**

| | First | Second | Third | Fourth | Total |
|---|---|---|---|---|---|
| | (In thousands, except per unit data) | | | | |
| 2007 | | | | | |
| Revenues | $ 824,028 | $ 999,113 | $ 940,392 | $ 1,085,555 | $ 3,849,088 |
| Operating income | 10,907 | 19,344 | 21,951 | 35,049 | 87,251 |
| Income from discontinued operations | 1,442 | 1,601 | 1,597 | 1,842 | 6,482 |
| Net income (loss) | (5,277) | 2,888 | 2,130 | 14,148 | 13,889 |
| Earnings (loss) per limited partner unit — basic | $ (0.36) | $ (0.06) | $ (0.10) | $ 0.31 | $ (0.20) |
| Earnings (loss) per limited partner unit — diluted | $ (0.36) | $ (0.06) | $ (0.10) | $ 0.19 | $ (0.20) |
| Basic and diluted senior subordinated A unit | $ — | $ — | $ — | $ — | $ — |

**(19) Condensed Consolidating Financial Statements**

In connection with the Partnership's filing of a shelf registration statement on Form S-3 with the Securities and Exchange Commission (the "Registration Statement"), all of the Partnership's wholly-owned subsidiaries, excluding minor subsidiaries, may issue unconditional guarantees of senior or subordinated debt securities of the Partnership in the event that the Partnership issues such securities from time to time under the Registration Statement. If issued, the guarantees will be full, irrevocable and unconditional. The Partnership does not provide separate financial statements of such subsidiaries because the Partnership has no independent assets or operations, the guarantees are full and unconditional and the non-guarantor subsidiaries are minor. There are no significant restrictions on the ability of the Partnership to obtain funds from any of its subsidiaries by dividend or loan.

**Schedule II**

**CROSSTEX ENERGY, L.P.**

**VALUATION AND QUALIFYING ACCOUNTS**

| | Balance at Beginning of Period | Charged to Costs and Expenses | Deductions | Balance at End of Period |
|---|---|---|---|---|
| | | {(In thousands) | | |
| Year ended December 31, 2008 Allowance for doubtful accounts | $ 985 | $ 2,670 | — | $ 3,655 |
| Year ended December 31, 2007 Allowance for doubtful accounts | $ 618 | $ 367 | — | $ 985 |
| Year ended December 31, 2006 Allowance for doubtful accounts | $ 259 | $ 359 | — | $ 618 |

**EXHIBIT INDEX**

| Number | | Description |
|---|---|---|
| 3.1 | — | Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779). |
| 3.2 | — | Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007). |
| 3.3 | — | Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007). |
| 3.4 | — | Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008). |
| 3.5 | — | Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779). |
| 3.6 | — | Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004). |
| 3.7 | — | Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779). |
| 3.8 | — | Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779). |
| 3.9 | — | 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). |
| 3.10 | — | 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). |
| 4.1 | — | Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.7 to Amendment No. 1 to our Registration Statement on Form S-3, file No. 333-128282). |
| 4.2 | — | Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LBI Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006). |
| 4.3 | — | Registration Rights Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007). |
| 10.1 | — | Fourth Amended and Restated Credit Agreement, dated November 1, 2005, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005). |
| 10.2 | — | First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006). |
| 10.3 | — | Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006). |
| 10.4 | — | Third Amendment to Fourth Amended and Restated Credit Agreement, effective as of March 28, 2007, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007). |

| Number | | Description |
|---|---|---|
| 10.5 | — | Fifth Amendment and Consent to Fourth Amended and Restated Credit Agreement, effective as of November 7, 2008, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008). |
| 10.6* | — | Sixth Amendment to Fourth Amended and Restated Credit Agreement, effective as of February 27, 2009, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties. |
| 10.7 | — | Commitment Increase Agreement, dated as of September 19, 2007, among Crosstex Energy, L.P., Bank of America, N.A., and certain lenders party thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated September 19, 2007, filed with the Commission on September 24, 2007). |
| 10.8 | — | Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006). |
| 10.9 | — | Letter Amendment No. 1 to Amended and Restated Note Purchase Agreement, effective as of March 30, 2007, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007). |
| 10.10 | — | Waiver and Letter Amendment No. 3 to Amended and Restated Note Purchase Agreement, effective as of November 7, 2008 , among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008). |
| 10.11* | — | Letter Amendment No. 4 to Amended and Restated Note Purchase Agreement, effective as of February 27, 2009, among Crosstex Energy, L.P. Prudential Investment Management, Inc. and certain other parties. |
| 10.12 | — | Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006). |
| 10.13† | — | Crosstex Energy GP, LLC Long-Term Incentive Plan, dated July 12, 2002 (incorporated by reference to Exhibit 10.4 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067). |
| 10.14† | — | Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005). |
| 10.15 | — | Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067). |
| 10.16† | — | Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067). |
| 10.17 | — | Senior Subordinated Series D Unit Purchase Agreement, dated as of March 23, 2007, 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 March 23, 2007, filed with the Commission on March 27, 2007). |
| 10.18† | — | Form of Performance Unit Agreement (incorporated by reference to our Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007). |
| 10.19 | — | Common Unit Purchase Agreement, dated as of April 8, 2008, by and among Crosstex Energy, L.P. and each of the Purchasers set forth Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Form 8-K dated April 9, 2008). |
| 21.1* | — | List of Subsidiaries. |
| 23.1* | — | Consent of KPMG LLP. |
| 23.2* | — | Consent of KPMG LLP. |
| 31.1* | — | Certification of the Principal Executive Officer. |

| Number | | Description |
|---|---|---|
| 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. |
| 99.1* | — | Consolidated Balance Sheet of Crosstex Energy GP, L.P. (Delaware limited partnership) and subsidiaries as of December 31, 2008. |

* Filed herewith.

† As required by Item 14(a)(3), this exhibit is identified as a compensatory benefit plan or arrangement

**SIXTH AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT AND CONSENT**

THIS SIXTH AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT AND CONSENT (this "Amendment") is entered into as of February 27, 2009 by and among each of the persons listed on the signature pages hereto as banks (the "Banks"), Crosstex Energy, L.P., a Delaware limited partnership (the "Borrower"), and Bank of America, N.A., as administrative agent (in such capacity, the "Administrative Agent") and as collateral agent (in such capacity, the "Collateral Agent").

ARTICLE I

BACKGROUND

A. The Banks, the Administrative Agent and the Borrower are parties to that certain Fourth Amended and Restated Credit Agreement dated as of November 1, 2005, as amended by the First Amendment dated as of February 24, 2006, the Second Amendment dated as of June 29, 2006, the Third Amendment dated as of March 28, 2007, the Fourth Amendment dated as of September 19, 2007 and the Fifth Amendment and Consent dated as of November 7, 2008 (as so amended, the "Credit Agreement"). Terms defined in the Credit Agreement and not otherwise defined herein have the same meanings when used herein.

B. The Borrower has requested, and the Majority Banks have agreed, to (1) consent to the modification of certain financial covenants under the Credit Agreement and (2) make certain additional amendments to the Credit Agreement as provided for herein.

C. The Borrower intends to amend the Note Agreement in order to accomplish similar amendments to the Note Agreement.

ARTICLE II

AGREEMENT

NOW THEREFORE, in consideration of the covenants, conditions and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and adequacy of which are all hereby acknowledged, the parties hereto covenant and agree as follows:

Section 1. Amendments to the Credit Agreement. The Credit Agreement is hereby amended as follows:

(a) Section 1.01 of the Credit Agreement is hereby amended by restating the following definitions to read in their entirety as follows:

"Applicable Margin" means, as of any date of determination, the following percentages determined as a function of the Leverage Ratio for the Borrower and its Subsidiaries on a Consolidated basis:

| Leverage Ratio | Eurodollar Rate Advances | Reference Rate Advances | Commitment Fees | Letter of Credit Fees |
|---|---|---|---|---|
| ≥ 5.00 | 4.00% | 3.00% | 0.50% | 4.00% |
| ≥ 4.25 and < 5.00 | 3.50% | 2.50% | 0.50% | 3.50% |
| ≥ 3.75 and < 4.25 | 3.25% | 2.25% | 0.50% | 3.25% |
| < 3.75 | 2.75% | 1.75% | 0.50% | 2.75% |

The foregoing ratio shall be determined from the Financial Statements of the Borrower and its Subsidiaries most recently delivered pursuant to Section 5.01(c) or Section 5.01(d) and certified to by a Responsible Officer in accordance with such Sections. Any change in the Applicable Margin shall be effective upon the date of delivery of the Financial Statements pursuant to Section 5.01(c) or Section 5.01(d), as the case may be, and receipt by the Administrative Agent of the compliance certificate required by such Sections. The Applicable Rate from the Sixth Amendment Effective Date until the next determination will be for the Leverage Ratio of greater than or equal to 5.00 to 1.00.

"Asset Disposition" means any sale, transfer, license, lease or other disposition (including any sale and leaseback transaction) of any property or any series of related dispositions of property by any Person, including any sale, assignment, transfer or other disposal, with or without recourse, of any notes or accounts receivable or any rights and claims associated therewith in which the property disposed either (a) generates EBITDA greater than or equal to 1% of EBITDA for the four fiscal quarter period ending as of the most recent fiscal quarter for which the Borrower has delivered Financial Statements pursuant to Section 5.01(c) or (d) or (b) has an aggregate book value greater than 1% of the book value of the Consolidated assets of the Borrower and its Subsidiaries as of the end of the most recent fiscal quarter for which the Borrower has delivered Financial Statements pursuant to Section 5.01(c) or (d); provided, that the term "Asset Disposition" shall not include any transaction permitted by (i) Section 6.04(a), (ii) the first $5,000,000 of Net Cash Proceeds received in any fiscal year of the Borrower or its Subsidiaries in the aggregate pursuant to Section 6.04(b), and (iii) Section 6.04(c), (d), (e), (f), (h) or (i).

"Credit Documents" means, collectively, this Agreement, the Notes, the Security Documents, the Guaranties, the Letter of Credit Documents, any Interest Rate Contract between the Borrower or any Subsidiary and a Bank or an Affiliate thereof, any Hydrocarbon Hedge Agreement between the Borrower or any Subsidiary and a Bank or an Affiliate thereof which is a party to the Intercreditor Agreement, the Fee Letter, any Cash Management Agreement between the Borrower or any

Subsidiary and a Cash Management Bank which is a party to the Intercreditor Agreement, and each other agreement, instrument or document executed at any time in connection with the foregoing documents, as each such Credit Document may be amended, modified, restated, or supplemented from time-to-time, provided, however, the definition of Credit Documents shall not include Hydrocarbon Hedge Agreements, Interest Rate Contracts or Cash Management Agreements for the purposes of Sections 7.03(c) and 9.01.

"EBITDA" means, for the Borrower and its Subsidiaries on a Consolidated basis for any period, (a) Net Income for such period plus (b) to the extent deducted in determining Net Income, Interest Expense, taxes, depreciation, amortization and other noncash items for such period minus (c) to the extent included in determining Net Income, all noncash items increasing Net Income for such period plus (d) to the extent deducted in determining Net Income, Costs of Amendments. Notwithstanding the foregoing, the purchase price of commodity derivative instruments, net of all proceeds from the sale of such instruments, may be amortized over the remaining term of such instruments.

For purposes of calculating the Leverage Ratio and Interest Coverage Ratio, EBITDA shall be calculated, on a pro forma basis, after giving effect to, without duplication, any permitted Acquisition occurring during the period commencing on the first day of such period to and including the date of such Acquisition (the "Reference Period"), as if such Acquisition occurred on the first day of the Reference Period. In making the calculation contemplated by the preceding sentence, EBITDA generated or to be generated by such acquired Person or by such acquired Property shall be determined in good faith by the Borrower based on reasonable assumptions and may take into account pro forma expenses that would have been incurred by the Borrower and its Subsidiaries in the operation of such acquired Person or acquired Property, during such period computed on the basis of personnel expenses for employees retained or to be retained by the Borrower and its Subsidiaries in the operation of such acquired Person or acquired Property and non-personnel costs and expenses incurred by the Borrower and its Subsidiaries in the operation of the Borrower's and its Subsidiaries' business at similarly situated facilities of the Borrower or any of its Subsidiaries; provided, however, that such pro forma calculations shall be reasonably acceptable to the Administrative Agent if the Borrower does not provide the Administrative Agent with an Approved Consultant's Report supporting such pro forma calculations.

For purposes of calculating the Leverage Ratio and the Interest Coverage Ratio, EBITDA shall be calculated by deducting, to the extent previously included in the calculation for any relevant period, EBITDA attributable to a particular asset subject to an Asset Disposition prepayment required by

Section 2.04(b)(ii) after giving effect to such Asset Disposition occurring during the period commencing on the first day of such period to and including the date of such Asset Disposition (the "Asset Disposition Reference Period"), as if such Asset Disposition occurred on the first day of the Asset Disposition Reference Period.

Notwithstanding any provision of this Agreement which may otherwise be to the contrary, if any lease pursuant to the Eunice Lease Documents is treated under GAAP as a Capital Lease, then, for all computations of EBITDA hereunder, such lease shall be treated as an operating lease and Net Income, Interest Expense, taxes, depreciation, amortization and other noncash items, for all purposes of determining EBITDA under this Agreement for any period, shall be adjusted as though such lease was accounted for as an operating lease.

"Eurodollar Rate" means, for any Interest Period with respect to a Eurodollar Rate Advance, the rate per annum equal to the British Bankers Association LIBOR Rate ("BBA LIBOR"), as published by Reuters (or other commercially available source providing quotations of BBA LIBOR as designated by the Administrative Agent from time to time) at approximately 11:00 a.m., London time, two Business Days prior to the commencement of such Interest Period, for Dollar deposits (for delivery on the first day of such Interest Period) with a term equivalent to such Interest Period. If such rate is not available at such time for any reason, then the "Eurodollar Rate" for such Interest Period shall be the rate per annum determined by the Administrative Agent to be the rate at which deposits in Dollars for delivery on the first day of such Interest Period in same day funds in the approximate amount of the Eurodollar Rate Advance being made, continued or converted by Bank of America, N.A. and with a term equivalent to such Interest Period would be offered by Bank of America's London Branch to major banks in the London interbank eurodollar market at their request at approximately 11:00 a.m. (London time) two Business Days prior to the commencement of such Interest Period.

Notwithstanding anything to the contrary contained herein, the Eurodollar Rate shall not be less than 2.75% per annum at any time.

"Interest Charge Coverage Ratio" means, for the Borrower and its Subsidiaries on a Consolidated basis, as of the end of any fiscal quarter, the ratio of (a) EBITDA for the four-fiscal quarter period then ended to (b) Cash Interest Expenses for the four-fiscal quarter period then ended.

"Interest Expense" means, for the Borrower and its Subsidiaries determined on a Consolidated basis, for any period, the total interest, letter of credit fees, and other fees incurred in connection with any Debt for such period (excluding all Costs of Amendments), whether paid or accrued,

including, without limitation, all commissions, discounts and other fees and charges owed with respect to letters of credit and bankers' acceptance financing, all as determined in conformity with GAAP. For purposes of calculating the Interest Charge Coverage Ratio, Interest Expense shall be calculated by deducting, to the extent previously included in the calculation for any relevant period, the amount of interest incurred by the Borrower in connection with (a) Advances that have been prepaid pursuant to Section 2.04(b)(ii) and (b) the principal amount of Notes that have been prepaid pursuant to paragraph 4A(ii)(a) of the Note Agreement, in both instances, during the period commencing on the first day of such period to and including the date of such prepayment.

"Leverage Ratio" means, for the Borrower and its Subsidiaries on a Consolidated basis, as of the end of any fiscal quarter, the ratio of (a) Funded Debt for the Borrower and its Subsidiaries on a Consolidated basis as of the end of such fiscal quarter to (b) EBITDA for the four fiscal quarters then ended, provided, however, the outstanding principal amount of the PIK Notes and the incurrence of any obligation to pay the Leverage Fee and the Noteholder Leverage Fee shall not be included in the definition of Funded Debt for the calculation of the Leverage Ratio.

"Material Subsidiary" shall mean a Subsidiary of the Borrower having: either (a) 1% or more of EBITDA for the four fiscal quarter period ending as of the most recent fiscal quarter for which the Borrower has delivered Financial Statements pursuant to Section 5.01(c) or (d); or (b) 1% of the book value of the Consolidated assets of the Borrower and its Subsidiaries as of the end of the most recent fiscal quarter for which the Borrower has delivered Financial Statements pursuant to Section 5.01(c) or (d); provided, however, to the extent that executing a Guaranty would result in adverse tax consequences with respect to any non-operating Subsidiary existing prior to the Sixth Amendment Effective Date (as reasonably determined by the Borrower), such non-operating Subsidiary shall not be considered a "Material Subsidiary" unless such non-operating Subsidiary has (i) 5% or more of EBITDA for the four fiscal quarter period ending as of the most recent fiscal quarter for which the Borrower has delivered Financial Statements pursuant to Section 5.01(c) or (d) or (ii) 5% of the book value of the Consolidated assets of the Borrower and its Subsidiaries as of the end of the most recent fiscal quarter for which the Borrower has delivered Financial Statements pursuant to Section 5.01(c) or (d).

"Obligations" shall mean all present and future indebtedness, liabilities and obligations of any kind and nature whatsoever of the Borrower or any Subsidiary, including, without limitation, default interest, interest accruing at the then applicable rate provided in this Agreement after the maturity of the loans and interest accruing at the then applicable rate provided in this Agreement after the filing of any petition in

bankruptcy, or the commencement of any insolvency, reorganization or like proceeding, relating to the Borrower or any Subsidiary, whether or not a claim for post-filing or post-petition interest is allowed in such proceeding), whether direct or indirect, absolute or contingent, due or to become due, or now existing or hereafter incurred, that arise under, out of, or in connection with, the Credit Agreement or any other Credit Document, any promissory notes given under the Credit Agreement or any other document made, delivered or given in connection therewith, whether on account of principal (including amounts of cash required to be deposited, pursuant to the Credit Documents, with the Administrative Agent or any Bank on account of drawn or undrawn letters of credit), interest, premium, fees, indemnities, costs, expenses or otherwise (including, without limitation, all fees and disbursements of counsel to the Administrative Agent and the Banks that are required to be paid by the Debtor Parties pursuant to the terms of the Credit Documents or this Agreement).

"Recovery Event" means any settlement of or payment in respect of any property or casualty insurance claim (excluding any claim in respect of business interruption) or any condemnation proceeding relating to any asset of the Borrower or any of its Subsidiaries, in which the subject property either (a) generates EBITDA greater than or equal to 1% of EBITDA for the four fiscal quarter period ending as of the most recent fiscal quarter for which the Borrower has delivered Financial Statements pursuant to Section 5.01(c) or (d) or (b) has an aggregate book value greater than 1% of the book value of the consolidated assets of the Borrower and its Subsidiaries as of the end of the most recent fiscal quarter for which the Borrower has delivered Financial Statements pursuant to Section 5.01(c) or (d).

"Reference Rate" means for any day a fluctuating rate per annum equal to the highest of the following, in each case, to the extent determinable by the Administrative Agent: (a) the Federal Funds Rate plus 1/2 of 1%, (b) the Eurodollar Rate with respect to Interest Periods of one month determined as of approximately 11:00 a.m. (London time) on such day, provided however, if such Eurodollar Rate is less than 2.75%, such rate shall be 2.75%, plus 1.00% and (c) the rate of interest in effect for such day as publicly announced from time to time by Bank of America as its "prime rate." The "prime rate" is a rate set by Bank of America based upon various factors including Bank of America's costs and desired return, general economic conditions and other factors, and is used as a reference point for pricing some loans, which may be priced at, above, or below such announced rate. Any change in such rate announced by Bank of America shall take effect at the opening of business on the day specified in the public announcement of such change.

"Reinvestment Event" means any Recovery Event in respect of which a Reinvestment Notice has been delivered.

"Reinvestment Notice" means a written notice executed by a Responsible Officer stating that no Event of Default has occurred and is continuing and that the Borrower (directly or indirectly through a Subsidiary) intends and expects to use all or a specified portion of the Net Cash Proceeds of a Recovery Event to acquire assets useful in its business and/or to repair Property, as applicable.

(b) Section 1.01 of the Credit Agreement is hereby amended by adding the following new defined terms to Section 1.01 in alphabetical order:

"Arkoma Sale" means the transactions contemplated by that certain Asset Purchase Agreement dated as of February 9, 2009, among Producers Gas Gathering, JV, Crosstex Arkoma, LLC, and Crosstex Energy Services, L.P.

"Capital Assets" means, with respect to any Person, all equipment, fixed assets and real Property or improvements of such Person, or replacements or substitutions therefor or additions thereto, that, in accordance with GAAP, have been or should be reflected as additions to property, plant or equipment on the balance sheet of such Person.

"Capital Expenditures" means, with respect to any Person for any period, any expenditure in respect of the purchase or other acquisition of any Capital Asset (excluding normal replacements and maintenance which are properly charged to current operations). For purposes of this definition, the purchase price (or, if such Capital Asset has already been purchased, the fair market value) of any Capital Asset that is traded in, swapped or exchanged for any existing Capital Asset or with insurance proceeds shall be included in Capital Expenditures only to the extent of the gross amount by which such purchase price exceeds the credit granted by the seller of such Capital Asset for the Capital Asset being traded in at such time or the amount of such insurance proceeds, as the case may be.

"Cash Interest Expense" means, for the Borrower and its Subsidiaries determined on a Consolidated basis, for any period, Interest Expense for such period, less, to the extent included in the calculation of Interest Expense, the sum of (a) the principal amount of the PIK Notes (to the extent attributable to interest for such period) and interest on the PIK Notes, (b) amortization of debt issuance costs, debt discount or premium and other financing fees and expenses incurred by the Borrower or any of its Subsidiaries, and (c) the incurrence of any obligation to pay the Leverage Fee and the Noteholder Leverage Fee.

"Cash Management Accounts" has the meaning specified in Section 5.20(a).

"Cash Management Agreement" means any agreement to provide cash management services, including treasury, depository, overdraft, credit or debit card, electronic funds transfer and other cash management arrangements.

"Cash Management Bank" means any Person that, at the time it enters into a Cash Management Agreement is a Bank or an Affiliate of a Bank and is or becomes a party to the Intercreditor Agreement, in its capacity, as a party to such Cash Management Agreement; provided, however, that if such Person ceases to be a Bank or an Affiliate of a Bank, such Person shall no longer be a "Cash Management Bank".

"Costs of Amendments" means all upfront, consent, legal, professional and advisory fees paid by the Borrower (whether or not incurred by the Borrower) in connection with the negotiation and execution, delivery and performance of the Borrower's obligations under (a) each amendment to this Agreement executed on or prior to the Sixth Amendment Effective Date, among the Borrower, the Banks party thereto, and the Administrative Agent and (b) each amendment to the Note Agreement executed on or prior to the Sixth Amendment Effective Date, among the Borrower, the Guarantors and the holders of the Note Obligations party thereto.

"ECF Capital Expenditures" means, for any period, without duplication, the sum of all expenditures made by the Borrower and its Subsidiaries during such period for Capital Assets, but excluding (a) any such expenditures financed with Excess Proceeds and (b) expenditures made with amounts paid to the Borrower and its Subsidiaries by third parties aiding in construction for such Capital Assets. For the sake of clarity, amounts paid to the Borrower and its Subsidiaries by third parties aiding in construction for Capital Assets that have not been expended in construction for such Capital Assets shall not be included in the calculation of ECF Capital Expenditures.

"Excess Cash Flow" means, for any fiscal year of the Borrower, the excess (if any) of (a) EBITDA for such fiscal year (without giving effect to any pro forma adjustments made to EBITDA as a result of Acquisitions or Asset Dispositions) over (b) the sum (for such fiscal year), without duplication, of (i) Cash Interest Expense, (ii) scheduled principal repayments on the Note Obligations and scheduled principal repayments and amortization of Debt permitted by Section 6.02(f), to the extent actually made, (iii) all taxes actually paid in cash by the Borrower and its Subsidiaries during such fiscal year (excluding items included in this calculation during the prior year as a reserve) or that will be paid within

six months after the end of such fiscal year and for which reserves have been established, (iv) all prepayments of Debt made by the Borrower pursuant to Section 2.03 in amounts equal to the corresponding Commitment reductions in connection with such prepayments, (v) ECF Capital Expenditures actually made by the Borrower and its Subsidiaries as permitted hereunder, but excluding any such ECF Capital Expenditures made in such fiscal year where a certificate in the form contemplated by the following clause, (vi) was previously delivered, and (vi) ECF Capital Expenditures that the Borrower or any of its Subsidiaries shall, during such fiscal year, become obligated to make but that are not made during such fiscal year, provided that the Borrower shall deliver a certificate to the Administrative Agent not later than 90 days after the end of such fiscal year, signed by a Responsible Officer and certifying that such ECF Capital Expenditures were made during such 90-day period and were not financed with Excess Proceeds.

"Excess Proceeds" shall mean the Net Cash Proceeds and Equity Issuance Proceeds (as applicable) that are not required to be applied as prepayments of (a) Advances under Section 2.04(b)(iii) and (iv) or (b) the Note Obligations under the Note Agreement.

"Hydrocarbon Cash Collateral" means the amount of cash and Permitted Investments pledged and deposited with or delivered to a Person by the Borrower or any Subsidiary as collateral for obligations of the Borrower or any Subsidiary under any Hydrocarbon Hedge Agreements.

"Leverage Fee" has the meaning specified in Section 2.04(b)(vii).

"Maximum Cash Balance" has the meaning specified in Section 5.20(b).

"Minimum Quarterly Distributions" shall have the meaning set forth in Section 1.1 of the Borrower Partnership Agreement.

"Newly Acquired Real Property Report" has the meaning specified in Section 5.01(n).

"Noteholder Leverage Fee means "Leverage Fee" as defined in the Note Agreement.

"PIK Notes" means "PIK Notes" as defined in the Note Agreement.

"Sixth Amendment Effective Date" means February 27, 2009.

(c) Section 1.01 of the Credit Agreement is hereby amended by deleting the following defined terms:

"Acquisition Adjustment Period"

"Scheduled Completion Date"

"Senior Leverage Ratio"

(d) Section 2.03(c) of the Credit Agreement is hereby added in its entirety to read as follows:

(c) The aggregate Commitments shall be permanently reduced on the dates and in the amounts set forth on the grid below:

| Effective Date of Permanent Reduction of Commitment | Amount of Permanent Reduction of Commitment |
|---|---|
| March 1, 2009 | $ 1,764,706 |
| April 1, 2009 | $ 588,235 |
| June 1, 2009 | $ 1,764,706 |
| July 1, 2009 | $ 588,235 |
| September 1, 2009 | $ 1,764,706 |
| October 1, 2009 | $ 588,235 |
| December 1, 2009 | $ 1,764,706 |
| January 1, 2010 | $ 588,235 |
| March 1, 2010 | $ 1,764,706 |
| April 1, 2010 | $ 588,235 |
| June 1, 2010 | $ 1,764,706 |
| June 18, 2010 | $ 15,000,000 |
| July 1, 2010 | $ 588,235 |
| June 18, 2011 | $ 15,000,000 |
| Total | $ 44,117,646 |

(e) Section 2.04(b) of the Credit Agreement is hereby restated in its entirety as follows:

(b) Mandatory.

(i) Reduction of Commitments. On the date of each reduction of the aggregate Commitments pursuant to Section 2.03 or if for any reason the outstanding amount of Advances plus the Letter of Credit Exposure exceeds the aggregate Commitments then in effect, the Borrower agrees to make a prepayment in respect of the outstanding amount of the Advances and/or Cash Collateralize the Letter of Credit Obligations to the extent, if any,

that the aggregate unpaid principal amount of all Advances plus the Letter of Credit Exposure exceeds the aggregate Commitments.

(ii) Asset Disposition. Upon the occurrence of any Asset Disposition or any Recovery Event (except (A) to the extent that a Reinvestment Notice shall be delivered in respect of such Recovery Event or (B) with respect to cash receipts in the ordinary course of business of the applicable recipient), then on the date of receipt by the Borrower or the applicable Subsidiary of the Net Cash Proceeds related thereto, the Advances shall immediately be prepaid by an amount equal to the amount of such Net Cash Proceeds (except to the extent such Net Cash Proceeds are otherwise required by the Note Agreement to be applied to the ratable prepayment of the Note Obligations); provided, that, notwithstanding the foregoing, on each Reinvestment Prepayment Date the Advances shall be prepaid by an amount equal to the Reinvestment Prepayment Amount with respect to the relevant Reinvestment Event (except to the extent such Reinvestment Prepayment Amount is otherwise required by the Note Agreement to be applied to the ratable prepayment of the Note Obligations). For purposes of calculating the Net Cash Proceeds received from an Asset Disposition or from a Recovery Event, such proceeds shall be determined as of the date of the applicable Asset Disposition or Recovery Event, whether or not received on such date, but no such amount shall be required to be applied to prepayment of the Advances pursuant to this Section until received by the applicable Person. The provisions of this Section do not constitute consent to the consummation of any Asset Disposition not permitted by Section 6.04. To the extent that the Borrower or applicable Subsidiary receives proceeds from any Recovery Event in excess of $10,000,000, such proceeds shall be maintained by the Collateral Agent as Cash Collateral for the Obligations and the Noteholder Obligations (in substantially the manner set forth in Section 2.13(g), with such funds being promptly released to the Borrower as funds are needed for reinvestment as a result of such Recovery Event) until a Reinvestment Prepayment Date has occurred.

(iii) Debt Issuance. If any Debt for borrowed money shall be issued or incurred by the Borrower or any of its Subsidiaries (excluding any Debt incurred in accordance with Section 6.02(a), (b), (c), (d), (e), (f), (h), and (j)), then on the date of such issuance or incurrence, the Advances shall be prepaid by an amount equal to the amount of the Net Cash Proceeds of such issuance or incurrence, except to the extent that such Net Cash Proceeds are otherwise required by the Note Agreement to be applied to the ratable prepayment of the Note Obligations. The

provisions of this Section do not constitute consent to the issuance or incurrence of any Debt by the Borrower or any of its Subsidiaries not otherwise permitted hereunder.

(iv) Equity Issuance. If the Borrower or any Subsidiary issues any Equity Interests, then Equity Issuance Proceeds received by the Borrower or any of its Subsidiaries shall be immediately applied to prepay the Advances on the date such Equity Issuance Proceeds are received provided, however, the Borrower shall not nor will it permit any Subsidiary to issue any Equity Interest if a Default shall be existing immediately after giving effect thereto or would result therefrom.

(v) Accrued Interest. Each prepayment under this Section 2.04(b) shall be accompanied by accrued interest on the amount prepaid to the date of such prepayment and amounts, if any, required to be paid pursuant to Section 2.10 as a result of such prepayment.

(vi) Permanent Commitment Reduction. At 5:00 pm on the date any mandatory prepayment under Section 2.04(b)(ii) (as a result of an Asset Disposition), 2.04(b)(iii), 2.04(b)(iv) or 2.04(b)(viii) becomes due and owing, the aggregate Commitments shall be automatically and permanently reduced by the applicable amount set forth in the grid below. Notwithstanding anything to the contrary contained herein, no reductions in the aggregate Commitments shall affect the availability or maximum amount of Letters of Credit in Section 2.13.

| | *Asset Dispositions and Excess Cash Flow* | *Debt* | *Equity* |
|---|---|---|---|
| Leverage Ratio (giving pro forma effect to such transaction and the use of proceeds thereof for each proportional level of Leverage Ratio) | Permanent Commitment reduction equals product of (x) amount of Advances required to be prepaid under Section 2.04(b)(ii) and (viii) (as applicable) and (y) the applicable percentage set forth below | Permanent Commitment reduction equals (x) product of the applicable percentage set forth below and the Net Cash Proceeds of the Debt issuance minus (y) amount of Note Obligations prepaid under paragraph 4A(ii)(c) of the Note Agreement | Permanent Commitment reduction equals (x) product of the applicable percentage set forth below and the amount of Advances required to be prepaid under Section 2.04(b)(iv) minus (y) amount of Note Obligations prepaid under paragraph 4A(ii)(d) of the Note Agreement |
| ≥4.50 | 100% | 100% | 50% |
| ≥3.50 and < 4.50 | 100% | 50% | 25% |
| < 3.50 | 100% | 0% | 0% |

(vii) Leverage Fee. The Borrower shall either make prepayments under this Agreement resulting in corresponding

Commitment reductions in accordance with Section 2.03(a) or 2.04(b)(vi) (other than as a result of Section 2.04(b)(viii)), as applicable, and the Note Obligations under the Note Agreement (not including any Yield-Maintenance Amounts as defined therein) in at least the cumulative amounts and on or before the dates set forth on the grid below or incur a leverage fee equal to the product of aggregate Commitments in effect on the date set forth on the grid below and the applicable percentage set forth on the grid below (collectively, the "Leverage Fee"). In the event that any voluntary prepayment is made pursuant to Section 2.04(a) in satisfaction of this Section 2.04(b)(vii), then the Borrower shall also permanently reduce the aggregate Commitments under Section 2.03(a) in an amount equal to such voluntary prepayment. Notwithstanding anything to the contrary contained herein, payments made and corresponding Commitment reductions related thereto under Section 2.03(c) and 2.04(b)(viii) or the payment of scheduled amortization of the Note Obligations shall not be included to determine Borrower's compliance with this Section 2.04(b)(vii). Such Leverage Fee shall be fully earned on the date indicated but shall be due and payable on the earlier of (a) Termination Date or (b) the Obligations are refinanced, whether by amendment and restatement or otherwise.

| Period Ending | Cumulative Prepayments Under this Agreement and Note Agreement | Leverage Fee Payable Under this Agreement (based on the aggregate Commitments) |
|---|---|---|
| September 30, 2009 | $ 100,000,000 | 1.00% |
| December 31, 2009 | $ 200,000,000 | 1.00% |
| March 31, 2010 | $ 300,000,000 | 2.00% |

To the extent that a consent from the Banks is necessary in order to permit a certain Asset Disposition for which the Net Cash Proceeds are to be included in the calculation of cumulative prepayments required hereunder, the Banks shall not charge a fee provided, however, such agreement not to charge a consent fee shall be limited to specific consents for which the sole purpose is to permit such Asset Disposition.

(viii) Excess Cash Flow. Within 90 days after the end of each of the fiscal years of the Borrower ending on December 31, 2009 and December 31, 2010, the Borrower shall prepay an amount initially equal to (A) if the Leverage Ratio is greater than or equal to 4.50 to 1.00, 75% of the Excess Cash Flow at such fiscal year end or (B) if the Leverage Ratio is less than 4.50 to 1.00, 50% of the Excess Cash Flow at such fiscal year end.

Each such prepayment shall be applied first to the Advances (except to the extent that such amount of Excess Cash Flow are otherwise required by the Note Agreement to be applied to the ratable prepayment of the Note Obligations) and second to Cash Collateralize all outstanding Letters of Credit. Any amount remaining after the prepayment of the Advances, the Note Obligations, and to Cash Collateralize Letters of Credit in accordance with the terms herein and the Note Agreement may be retained by the Borrower for use in the ordinary course of its business. Upon the drawing of any Letter of Credit that has been Cash Collateralized, the funds held as Cash Collateral shall be applied (without any further action by or notice to or from the Borrower or any Subsidiary) to reimburse the Issuing Bank or the Banks, as applicable.

(f) Section 2.08(e) is hereby added to the Credit Agreement to read in its entirety as follows:

(e) If, as a result of any restatement of or other adjustment to the financial statements of the Borrower, the Borrower or the Majority Banks determine in good faith that (i) the Leverage Ratio as calculated by the Borrower as of any applicable date was inaccurate and (ii) a proper calculation of the Leverage Ratio would have resulted in higher pricing for such period, the Borrower shall immediately and retroactively be obligated to pay to the Administrative Agent for the account of the applicable Banks, promptly on demand by the Administrative Agent (or, after the occurrence of an actual or deemed entry of an order for relief with respect to the Borrower under the Bankruptcy Code of the United States, automatically and without further action by the Administrative Agent or any Bank), an amount equal to the excess of the amount of interest and fees that should have been paid for such period over the amount of interest and fees actually paid for such period. This paragraph shall not limit the rights of the Administrative Agent or any Bank under any other provision of this Agreement. The Borrower's obligations under this paragraph shall survive the termination of the aggregate Commitments and the repayment of all other Obligations hereunder.

(g) Section 2.13(a)(ii)(A) of the Credit Agreement is hereby restated in its entirety as follows:

(A) unless such issuance, increase, or extension would not cause the Letter of Credit Exposure to exceed the lesser of (i) $300,000,000 minus the aggregate amount of all then existing Hydrocarbon Cash Collateral and (ii) the aggregate Commitments less the aggregate outstanding principal amount of all Advances;

(h) Section 2.15 of the Credit Agreement is hereby deleted in its entirety.

(i) The penultimate sentence in Section 4.05 of the Credit Agreement is hereby restated in its entirety as follows:

Since September 30, 2008, no Material Adverse Effect has occurred.

(j) Section 3.02(a) of the Credit Agreement is hereby amended to delete the "and" at the end thereof.

(k) Section 3.02(b) of the Credit Agreement is hereby amended to delete the "." at the end thereof and replace it with "; and".

(l) Section 3.02(c) of the Credit Agreement is hereby added to read in its entirety as follows:

(c) after giving effect to the receipt of the proceeds of the requested Borrowing and the anticipated cash receipts and cash uses of the Borrower and its Subsidiaries on the date of the applicable Borrowing and the next Business Day, the aggregate balances in the Cash Management Accounts on such next Business Day shall not be in excess of $25,000,000.

(m) The introductory language of Section 5.01 of the Credit Agreement is hereby restated in its entirety as follows:

Section 5.01. Reporting Requirements. The Borrower will furnish to the Administrative Agent:

(n) Section 5.01(b) of the Credit Agreement is hereby restated in its entirety as follows:

(b) Monthly Financials. As soon as available and in any event within 35 days after the end of each month of each calendar year, commencing with the month ending February 28, 2009, an unaudited Consolidated balance sheet of the Borrower and its Subsidiaries as of the end of such month and unaudited Consolidated statements of operations, changes in partners' capital and cash flows of the Borrower and its Subsidiaries for the period commencing at the end of the preceding fiscal year and ending with the end of such month, setting forth in each case in comparative form the corresponding figures for the corresponding period of the preceding fiscal year and the actual to budgeted performance, all in reasonable detail and duly certified (subject to normal year-end audit adjustments and the absence of footnotes) by the chief financial officer, chief accounting officer or Vice President — Finance of the Ultimate General Partner as having been prepared in accordance with GAAP, together with a certificate of said officer stating that no Default has occurred and is continuing or, if a Default has occurred and is continuing, a statement as to the nature thereof and the action that the Borrower proposes to take with respect thereto.

(o) Section 5.01(l) of the Credit Agreement is hereby amended to delete the "and" at the end thereof.

(p) Section 5.01(m) of the Credit Agreement is hereby amended to delete the "." at the end thereof and replace it with ";".

(q) Section 5.01(n) of the Credit Agreement is hereby added to read in its entirety as follows:

(n) Interests in Real Property. As soon as available, but in any event within 60 days after the end of each fiscal quarter of each fiscal year of the Borrower, commencing with the fiscal quarter ending March 31, 2009, a summary of substantially all new real property interests (including owned and leased properties, easements and other property interests) acquired and recorded by the Borrower or any Subsidiary ("Newly Acquired Real Property Report") during the preceding fiscal quarter;

(r) Section 5.01(o) of the Credit Agreement is hereby added to read in its entirety as follows:

(o) Capital Expenditures. As soon as available, but in any event within 45 days after the end of each fiscal quarter of each fiscal year of the Borrower, commencing with the fiscal quarter ending March 31, 2009, a report detailing Capital Expenditures (i) actually made during such fiscal year of the Borrower compared to the budgeted amount therefor and (ii) projected for the remainder of such fiscal year;

(s) Section 5.01(p) of the Credit Agreement is hereby added to read in its entirety as follows:

(p) Annual Budget. As soon as available, but in any event within 60 days after the end of each fiscal year of the Borrower, an annual business plan and budget of the Borrower and its Subsidiaries on a Consolidated basis, prepared on a basis consistent with past practices, including forecasts prepared by management of the Borrower, in form reasonably satisfactory to the Administrative Agent;

(t) Section 5.01(q) of the Credit Agreement is hereby added to read in its entirety as follows:

(q) 13 Week Cash Flow Budget and Monthly Operating Report. As soon as available, but in any event within 35 days after the end of each calendar month, (i) a rolling 13-week cash flow budget in form mutually satisfactory to the Administrative Agent and the Borrower, including forecasts of receipts and disbursements prepared by management of the Borrower and a comparison of actual to budgeted performance and (ii) a report of key operating metrics in form mutually satisfactory to the Administrative Agent and the Borrower; and

(u) Section 5.01(r) of the Credit Agreement is hereby added to read in its entirety as follows:

(r) Post-Closing Report. Within 90 days after the Sixth Amendment Effective Date, a report on the progress of completing the post-closing requirements set forth in Section 5.21.

(v) Section 5.01 of the Credit Agreement is hereby amended by deleting the last paragraph thereof in its entirety.

(w) Section 5.13 of the Credit Agreement is hereby restated in its entirety as follows:

Section 5.13. Use of Proceeds. The proceeds of Advances will be used by the Borrower (a) to refinance existing Debt to the extent not prohibited hereunder, (b) for Capital Expenditures to the extent permitted by Section 6.12, (c) for working capital, including the issuance of Letters of Credit, (d) to fund Minimum Quarterly Distributions and Quarterly Distributions to the extent permitted by Section 6.06, (e) to pay fees, costs and expenses owed pursuant to this Agreement, (f) as Hydrocarbon Cash Collateral; provided, however, Hydrocarbon Cash Collateral shall not (i) be provided to any Person other than to secure or support trading on the New York Mercantile Exchange and (ii) exceed $50,000,000 at any time outstanding and (g) for other general partnership purposes. The Borrower is not engaged in the business of extending credit for the purpose of purchasing or carrying margin stock (within the meaning of Regulation U). No proceeds of the Borrowings will be used to purchase or carry any margin stock in violation of Regulations T, U or X.

(x) Section 5.17 of the Credit Agreement is hereby added in its entirety to read as follows as follows:

Section 5.17. Newly Acquired Real Property. Within 90 days (or such longer period as permitted by the Collateral Agent in its sole discretion) after each Newly Acquired Real Property Report is due but in any event within 180 days after each Newly Acquired Real Property Report is due, the Collateral Agent shall have received deeds of trust, trust deeds, deeds to secure debt, mortgages, leasehold mortgages and leasehold deeds of trust, in form reasonably satisfactory to the Collateral Agent and its counsel, covering all real property interests owned by the Borrower and each Guarantor as reflected on the Newly Acquired Real Property Report (other than any such real property that the Collateral Agent and Majority Banks determine a perfected Lien is unnecessary due to the cost in relation to the benefit; provided, however, that such determination by the Majority Bank(s) shall not be required so long as the aggregate amount of the cost of all real property with respect to which the Collateral Agent has

determined under this Section 5.17 a lien is unnecessary does not exceed $5,000,000), duly executed by the Borrower or such Subsidiary.

(y) Section 5.18 of the Credit Agreement is hereby added in its entirety to read as follows:

Section 5.18. Quarterly Update Calls. The Borrower shall have a periodic update call with the Administrative Agent and the Banks within 45 days after the last Business Day of each fiscal quarter of the Borrower (or at another time reasonably requested by the Administrative Agent) to discuss matters reasonably requested by the Administrative Agent and the Banks including but not limited to progress updates on the Borrower's strategic alternatives.

(z) Section 5.20 of the Credit Agreement is hereby added in its entirety to read as follows:

Section 5.20. Deposit Accounts, Disbursement Accounts and Other Cash Management Accounts. (a) The Borrower shall and cause its Subsidiaries to maintain its deposit accounts, disbursement accounts and other cash management accounts (collectively, the "Cash Management Accounts") with a Bank or an Affiliate of a Bank, provided, however, to the extent that a Cash Management Account is with a Bank or an Affiliate of a Bank that ceases to be a party to the Credit Documents, the Borrower shall cause such account to be transferred to another Bank or closed within 30 days.

(b) The Borrower and its Subsidiaries shall not maintain cash balances for longer than 5 consecutive Business Days in excess of $25,000,000 in the aggregate in their Cash Management Accounts (the "Maximum Cash Balance"). Any amounts in excess of the Maximum Cash Balance after 5 consecutive Business Days shall be immediately paid by the Borrower to the Advances (without a corresponding Commitment reduction).

(aa) Section 5.21 of the Credit Agreement is hereby added in its entirety to read as follows:

Section 5.21. Post-Closing Covenants for Sixth Amendment.

(a) Within 90 days (or such longer period as permitted by the Collateral Agent in its sole discretion) after the Sixth Amendment Effective Date, but in any event within 180 days after the Sixth Amendment Effective Date, the Borrower shall deliver to the Collateral Agent the following:

(i) deeds of trust, trust deeds, deeds to secure debt, mortgages, leasehold mortgages and leasehold deeds of trust, in form reasonably

satisfactory to the Collateral Agent and its counsel, and covering all unencumbered property interests held by the Borrower and each Guarantor as reflected on the Perfection Certificate (other than any such real property that the Collateral Agent and Majority Banks determine a perfected Lien is unnecessary due to the cost in relation to the benefit; provided, however, that such determination by the Majority Bank(s) shall not be required so long as the aggregate amount of the cost of all real property with respect to which the Collateral Agent has determined under this Section 5.21(a)(i) a lien is unnecessary does not exceed $10,000,000), duly executed by the Borrower or such Guarantor;

(ii) account control agreements in form reasonably satisfactory to the Collateral Agent and duly executed by the appropriate parties with respect to each deposit account and each securities account of the Borrower and each Subsidiary that is not already the subject to an account control agreement in favor of the Collateral Agent; and

(iii) evidence that all insurance required to be maintained pursuant to the Credit Documents has been obtained and is in effect, together with the certificates of insurance, naming the Collateral Agent, on behalf of the Banks, as an additional insured or loss payee, as the case may be, under all insurance policies maintained with respect to the assets and properties of the Borrower and its Subsidiaries that constitute Collateral.

(b) Within 45 days after the Sixth Amendment Effective Date, the Borrower shall deliver to the Collateral Agent, a complete and duly executed updated Perfection Certificate in form and substance reasonably satisfactory to counsel to the Administrative Agent.

(bb) Sections 6.01 through 6.04 of the Credit Agreement are hereby restated in their entirety as follows:

Section 6.01. Liens, Etc. The Borrower will not create, incur, assume or suffer to exist, or permit any Subsidiary to create, incur, assume or suffer to exist, any Lien, or enter into any agreement with any other Person not to create any Lien, on or with respect to any of its properties of any character (including accounts receivable) whether now owned or hereafter acquired, or sign or file, or permit any Subsidiary to sign or file, under the Uniform Commercial Code of any jurisdiction, a financing statement that names the Borrower or any Subsidiary as debtor (except in connection with true leases), or sign, or permit any Subsidiary to sign, any security agreement authorizing any secured party thereunder to file such a financing statement (except in connection with true leases), excluding, however, from the operation of the foregoing restrictions the following:

(a) Liens created by the Security Documents;

(b) Permitted Liens;

(c) Liens securing obligations of such Person as lessee under Capital Leases permitted by Section 6.02(f);

(d) purchase-money Liens on property acquired or held by the Borrower or any Subsidiary in the ordinary course of business, to secure the purchase price of such property or to secure Debt incurred solely for the purpose of financing the acquisition of such property to be subject to such Liens, or Liens existing on any such property at the time of acquisition thereof (or at the time the Borrower acquires the Subsidiary owning such property), or renewals or refinancings of any of the foregoing Liens for the same or a lesser amount; provided, however, that (i) no such Lien may extend to or cover any property other than the property being acquired and improvements and accessions thereto and proceeds thereof, (ii) no such renewal or refinancing may extend to or cover any property not previously subject to the Lien being renewed or refinanced, (iii) the Debt secured thereby does not exceed the cost or fair market value, whichever is lower, of the property being acquired on the date of acquisition and (iv) the aggregate principal amount of Debt at any time outstanding secured by such Liens may not exceed the amount permitted by paragraph 6.02(f);

(e) the negative pledge contained in the Note Agreement and the negative pledge contained in any agreement, instrument or document executed at any time in connection with Debt permitted by Section 6.02(k); provided, however that any such negative pledge in connection with Debt permitted by Section 6.02(k) shall not place any restriction on the creation or existence of any Lien now or hereafter securing the Obligations or, as a result of the creation or existence of any Lien securing the Obligations, cause or require the creation of any Lien securing such Debt;

(f) options, put and call arrangements, rights of first refusal, setoff rights and customary limitations and restrictions constituting negative pledges contained in, and limited to, specific leases, licenses, conveyances, partnership agreements and co owners' agreements, and similar conveyances and agreements to the extent that any such Lien referred to in this clause does not materially impair the use of the Property covered by such Lien for the purposes for which such Property is held or materially impair the value of such Property subject thereto;

(g) Liens incurred in the ordinary course of business of the Borrower or any Subsidiary with respect to obligations (other than Debt for borrowed money) that do not exceed $10,000,000 at any one time outstanding;

(h) licenses or leases or subleases as licensor, lessor or sublessor of any of its Property, including intellectual property, in the ordinary course of business;

(i) Liens represented by the escrow of cash or Permitted Investments securing the obligations of the Borrower or any Subsidiary under any agreement to acquire, or pursuant to which it acquired, any Property, which Liens secure the obligations of the Borrower or such Subsidiary to the seller of such Property, provided that such acquisition is permitted pursuant to the terms of this Agreement;

(j) any Lien permitted by any Mortgage;

(k) Liens on assets pursuant to merger agreements, stock or asset purchase agreements and similar agreements in respect of the disposition of such assets, provided that such merger agreement, stock or asset purchase agreement or similar agreement in respect of the disposition of such asset is permitted pursuant to the terms of this Agreement;

(l) the negative pledge contained in the Promissory Note of Crosstex Louisiana Energy, L.P. dated April 2, 2004, payable to the order of Borrower; and

(m) Liens on any Hydrocarbon Cash Collateral permitted under Section 5.13(f).

Section 6.02. Debt. The Borrower will not create, incur, assume or suffer to exist, or permit any Subsidiary to create, incur, assume or suffer to exist, any Debt other than the following:

(a) Debt under the Credit Documents;

(b) Debt existing on the date of this Agreement and described in Schedule 6.02, including renewals and refinancings of such Debt, so long as the principal amount thereof is not increased (other than to pay any associated premiums, fees and expenses);

(c) Debt under one or more Interest Rate Contract or Hydrocarbon Hedge Agreement (provided that the parties to this Agreement hereby agree that the obligations of the Borrower to the Banks in respect of any Interest Rate Contract or Hydrocarbon Hedge Agreement are secured by the Security Documents, but only, with respect to each such Bank, if and so long as such Bank remains a Bank);

(d) Debt in respect of endorsement of negotiable instruments in the ordinary course of business;

(e) Debt between the Borrower and any Subsidiary or between Subsidiaries, provided that (i) such Debt is noted on the books and records of the Borrower and its Subsidiaries and (ii) in the case of any Debt owed by the Borrower to any Subsidiary that is not a Guarantor, such Debt is subordinated to the Obligations of the Borrower under the Credit Documents on terms and conditions, and pursuant to documentation, in form and substance satisfactory to the Administrative Agent in its sole reasonable discretion;

(f) Debt in respect of Capital Leases and Debt secured by Liens permitted by Section 6.01(d) not exceeding $70,000,000 in aggregate amount equivalent to principal at any time outstanding;

(g) [Intentionally Omitted];

(h) if any lease pursuant to the Eunice Lease Documents is treated under GAAP as a Capital Lease, then, any such Debt which may be attributable to the Eunice Lease Documents;

(i) unsecured Debt in addition to Debt otherwise permitted herein, not exceeding $30,000,000 in aggregate principal amount at any time outstanding, provided that if such Debt is issued or incurred on or after the Sixth Amendment Effective Date, such Debt has been issued or incurred by the Borrower or a Subsidiary that is a Guarantor;

(j) Debt under the Note Agreement in an aggregate principal amount not to exceed $480,000,000 (not including the amount of any PIK Notes) as such amount shall be reduced by the scheduled amortization repayments of principal; and

(k) unsecured Funded Debt of the Borrower and/or a Finance Entity and/or any unsecured guaranty by the Borrower or any Guarantor of such Funded Debt of the Borrower or any Affiliate of the Borrower; provided that (i) the Borrower is in compliance with Section 6.14 immediately after giving effect to the incurrence of any such Funded Debt or guaranty determined based upon the outstanding amount of Funded Debt of the Borrower and its Subsidiaries on a Consolidated basis immediately after giving effect to such incurrence, EBITDA for the four fiscal quarters most recently ended on or before the date of such incurrence and the maximum Leverage Ratio allowed as of the end of the fiscal quarter most recently ended on or prior to the date of such incurrence (and in the case of any guaranty of Funded Debt of the Borrower or any other Affiliate of the Borrower, the aggregate amount of such Funded Debt so guaranteed shall be "Funded Debt" of the Borrower for purposes of calculating the Leverage Ratio), (ii) such Funded Debt does not impose any financial or other "maintenance" covenants on the Borrower or any of the Subsidiaries that are more onerous than the

covenants set forth in this Agreement, (iii) such Funded Debt shall not require any scheduled payment on account of principal (whether by redemption, purchase, retirement, defeasance, set-off or otherwise) prior to the Termination Date and (iv) such Funded Debt shall contain terms and conditions that are customary for such transactions.

Section 6.03. Mergers, Acquisitions, Etc. The Borrower will not merge or consolidate with or into, or sell, lease, transfer or otherwise dispose of (whether in one transaction or in a series of transactions) all or substantially all of its Property (whether now owned or hereafter acquired) to, or enter into any Acquisition, or permit any Subsidiary to do any of the foregoing, except for the following:

(a) so long as no Default has occurred and is continuing or would be caused thereby, the Borrower or any Subsidiary may make any Acquisition whereby the sole cash compensation paid by the Borrower or any Subsidiary for such Acquisition is made from Excess Proceeds; provided, however, that any such Acquisition shall be permitted only if, (i) before the effectiveness of such Acquisition and to the extent required by the Majority Banks, the Borrower delivers to the Collateral Agent (A) guaranties, mortgages, deeds of trust, security agreements, releases, UCC financing statements and UCC terminations, duly executed by the parties thereto, in form and substance satisfactory to the Collateral Agent and accompanied by UCC searches, title investigations and legal opinions (except with respect to priority) demonstrating that, upon the effectiveness of such Acquisition and the recording and filing of any necessary documentation, the Collateral Agent will have an Acceptable Security Interest on the Property to be acquired and (B) evidence of company authority to enter into and environmental assessments with respect to such Acquisition; (ii) the Borrower or such Guarantor is the acquiring or surviving entity; (iii) no Default or Event of Default exists and the Acquisition would not reasonably be expected to cause a Default or Event of Default; (iv) after giving effect to such Acquisition on a *pro forma* basis, the Borrower would have been in compliance with all of the covenants contained in this Agreement, including, without limitation, Sections 6.13 and 6.14 as of the end of the most recent fiscal quarter, (v) the acquisition target is in the same or similar line of business as Borrower and its Subsidiaries, and (vi) the terms of Section 6.10 are satisfied;

(b) so long as no Default has occurred and is continuing or would be caused thereby, any Subsidiary may sell or otherwise transfer all of its Property to, or merge into or consolidate with, any other Subsidiary or the Borrower; provided, however, that any such disposition, merger or consolidation shall be permitted only if, before the effectiveness of such disposition, merger or consolidation and to the extent reasonably required

by the Administrative Agent, the Borrower delivers to the Collateral Agent documents of the type described in the proviso to clause (a) above;

(c) so long as no Default has occurred and is continuing or would be caused thereby, any Subsidiary of the Borrower may sell or otherwise transfer all of its Property to, or merge into or consolidate with, any other Person so long as such transaction is not prohibited by Section 6.04;

(d) any Subsidiary of the Borrower may dissolve so long as all of its Property is distributed to the Borrower or a Subsidiary; provided that if such dissolving Subsidiary is a Guarantor, all of its Property shall be distributed to the Borrower or another Guarantor;

(e) the Borrower and its Subsidiaries may acquire Property in the ordinary course of business;

(f) the El Paso Acquisition; and

(g) so long as no Default has occurred and is continuing or would be caused thereby, the Borrower may merge with or consolidate with any other Person provided, however, that such merger or consolidation shall be permitted only if, (i) the Borrower is the surviving entity of such merger or consolidation, (ii) no Change of Control results therefrom, (iii) immediately after giving effect to such merger or consolidation, the Leverage Ratio and the Interest Charge Coverage Ratio shall not be negatively impacted, (iv) the Collateral Agent will have an Acceptable Security Interest in all of the Collateral and each Guarantor will remain a Guarantor of the Obligations (unless such Guarantor is dissolved or merged into another Guarantor in connection with such transaction as otherwise permitted by this Section 6.03), and (v) the result of such merger taken as a whole will not be materially adverse to the interests of the Banks; provided, however, if as a result of such transaction the Borrower's entity type (e.g., corporation, partnership, limited liability company or other) or tax nature changes (A) the Borrower shall deliver to the Banks such opinions of counsel and corporation, limited liability company or partnership documents in connection therewith as the Majority Bank(s) may reasonably request and (B) the Borrower and the Banks agree that this Agreement will be amended in a manner reasonably satisfactory to the Majority Banks(s) (x) to make appropriate changes to reflect any changes to the entity type and/or tax nature of the Borrower while preserving the substance and terms of this Agreement and (y) without the payment of a consent fee or other fee with respect solely to the amendments to this Agreement specified in clause (x).

Section 6.04. Sales, Etc. of Property. The Borrower will not sell, lease, transfer or otherwise dispose of, or permit any Subsidiary to sell,

lease, transfer or otherwise dispose of, any of its Property, except for the following:

(a) sales of inventory in the ordinary course of business;

(b) sales, leases, transfers and other dispositions in the ordinary course of business of worn out or other Property that is no longer useful in the conduct of the business of the Borrower or any Subsidiary;

(c) liquidations or other dispositions of cash and Permitted Investments;

(d) so long as no Default has occurred and is continuing or would be caused thereby, sales and other transfers of Property from the Borrower or any Subsidiary to the Borrower or to any other Subsidiary; provided, however, that any such sale or other transfer of real property or equity interests shall be permitted only if, before the effectiveness of such sale or other transfer and to the extent required by the Majority Banks, the Borrower delivers to the Collateral Agent documents of the type described in the proviso to Section 6.03(a);

(e) sales of Property resulting from the condemnation thereof;

(f) sales or discounts of overdue accounts receivable in the ordinary course of business, in connection with the compromise or collection thereof;

(g) so long as no Default has occurred and is continuing or would be caused thereby, sales, leases, transfers and other dispositions of Property for consideration not exceeding $10,000,000 in the aggregate in any fiscal year of the Borrower (such amount not to include the proceeds of the Arkoma Sale, any sale, lease, or transfer permitted in clause (h) herein after the Sixth Amendment Effective Date, or other disposition permitted by any of the other provisions of this Section 6.04), provided that the Net Cash Proceeds thereof are used to prepay the Advances to the extent required by Section 2.04(b);

(h) sales or transfers of new equipment by the Borrower or any Subsidiary in the ordinary course of business consistent with historical practice to any Person whereby the Borrower or any Subsidiary shall then or thereafter rent or lease as lessee such new equipment or any part thereof to use for substantially the same purpose or purposes as such new equipment sold or transferred; and

(i) relatively contemporaneous like-kind exchanges in the ordinary course of business and consistent with historical practice not to exceed $10,000,000 in the aggregate in any fiscal year.

(cc) Section 6.06 of the Credit Agreement is hereby restated in its entirety as follows:

Section 6.06. Distributions, Etc. The Borrower will not pay any management fee or similar fee of any sort to any Affiliate thereof or to any other Person, declare or pay any dividends or distributions, purchase, redeem, retire, defease or otherwise acquire for value any of its equity interests or any warrants, rights or options to acquire such equity interests, now or hereafter outstanding, return any capital to its equity-holders as such, or make any distribution of Property, equity interests, warrants, rights, options, obligations or securities to its equity-holders as such, or permit any Subsidiary to purchase, redeem, retire, defease or otherwise acquire for value any equity interests in the Borrower or any warrants, rights or options to acquire such equity interests or to pay any such fee, except for the following:

(a) the Borrower and any Subsidiary may pay any management fee or similar fee of any sort to any Affiliate of the Borrower or its Subsidiaries pursuant to the Borrower Partnership Agreement, the CESL Partnership Agreement or the Omnibus Agreement;

(b) provided that no PIK Notes are outstanding and no Default has occurred and is continuing or would be caused thereby (i) so long as the Leverage Ratio is less than 4.25:1.00 but greater than or equal to 4.00:1.00 (after giving *pro forma* effect to such Minimum Quarterly Distributions described hereunder), the Borrower may declare and pay Minimum Quarterly Distributions and (ii) so long as the Leverage Ratio is less than 4.00:1.00 (after giving *pro forma* effect to such Quarterly Distributions described hereunder), the Borrower may declare and pay Quarterly Distributions;

(c) the Borrower may pay Minimum Quarterly Distributions and Quarterly Distributions within 60 days after the date of declaration thereof if, at the date of declaration, such payment would comply with clause (b) of this Section 6.06;

(d) the Borrower and its Subsidiaries may declare and pay dividends and other distributions payable solely in Equity Interests; and

(e) any Subsidiary may pay dividends, or make other distributions, to the Borrower or to any wholly-owned Subsidiary of the Borrower.

(dd) Section 6.12 of the Credit Agreement is hereby restated in its entirety as follows:

Section 6.12. Capital Expenditures. The Borrower will not, or permit any Subsidiary to, make or become legally obligated to make any

Capital Expenditure, except for Capital Expenditures in the ordinary course of business not exceeding, in the aggregate for the Borrower and its Subsidiaries during each fiscal year set forth below, the amount set forth opposite such fiscal year;

| Fiscal Year | Amount |
|---|---|
| 2009 | $120,000,000 |
| 2010 | $75,000,000 |

provided, however; that (i) any amounts of permitted Capital Expenditures not made during any fiscal year may be carried forward and expended during the subsequent fiscal year, (ii) Capital Expenditures in the amount of $18,400,000 that, in accordance with GAAP, have been accrued by the Borrower on its financial statements for the fiscal year ended December 31, 2008 but made in 2009 shall be excluded when calculating the Capital Expenditures made in 2009, and (iii) the limitation on Capital Expenditures set forth above for fiscal year 2010 shall not apply after the Leverage Ratio as of the end of each fiscal quarter for four consecutive four fiscal quarters for the Borrower and its Subsidiaries on a Consolidated basis is less than 4.25 to 1.00. Notwithstanding anything to the contrary contained herein, Capital Expenditures made with Excess Proceeds shall be excluded from the calculation of aggregate Capital Expenditures permitted hereunder for any fiscal year.

(ee) Section 6.13 of the Credit Agreement is hereby restated in its entirety as follows:

Section 6.13. Interest Charge Coverage Ratio. The Borrower shall not, as of the end of any fiscal quarter, permit the Interest Charge Coverage Ratio for the Borrower and its Subsidiaries on a Consolidated basis to be less than the ratio set forth below opposite such period:

| Period Ending | Minimum Interest Charge Coverage Ratio |
|---|---|
| March 31, 2009 | 1.75 to 1.00 |
| June 30, 2009 | 1.50 to 1.00 |
| September 30, 2009 | 1.30 to 1.00 |
| December 31, 2009 | 1.15 to 1.00 |
| March 31, 2010 | 1.25 to 1.00 |
| June 30, 2010 | 1.50 to 1.00 |
| September 30, 2010 and December 31, 2010 | 1.75 to 1.00 |
| March 31, 2011 and thereafter | 2.50 to 1.00 |

(ff) Section 6.14 of the Credit Agreement is hereby restated in its entirety as follows:

Section 6.14. Leverage Ratio. The Borrower shall not, as of the end of any fiscal quarter, permit the Leverage Ratio for the Borrower and

its Subsidiaries on a Consolidated basis to be greater than the ratio set forth below opposite such period:

| Period Ending | Maximum Leverage Ratio |
|---|---|
| March 31, 2009 | 7.25 to 1.00 |
| June 30, 2009 and September 30, 2009 | 8.25 to 1.00 |
| December 31, 2009 | 8.50 to 1.00 |
| March 31, 2010 | 8.00 to 1.00 |
| June 30, 2010 | 6.65 to 1.00 |
| September 30, 2010 | 5.25 to 1.00 |
| December 31, 2010 | 5.00 to 1.00 |
| March 31, 2011 and thereafter | 4.50 to 1.00 |

(gg) Section 6.17 of the Credit Agreement is hereby restated in its entirety as follows:

The Borrower may not make any optional or scheduled payments or prepayments on account of principal (whether by redemption, purchase, retirement, defeasance, set-off or otherwise) in respect of the Private Notes prior to the Termination Date, other than scheduled principal payments (including, but not limited to, mandatory prepayments) and optional prepayments made in connection with the Noteholder Leverage Fee. The Borrower will not amend, supplement or otherwise modify any term of the Note Agreement without the prior written consent of the Majority Banks, which consent will not be unreasonably withheld, which amendment, supplement or modification would have the effect of (i) increasing the outstanding principal amount of the Note Obligations over $480,000,000, (ii) increasing the rate of interest except with respect to imposing the default rate as provided for in the Note Agreement on the date hereof or any fees charged on the Note Obligations, (iii) adding any affirmative covenant, negative covenant or event of default; (iv) changing any affirmative covenant, negative covenant or event of default, or any definition used therein, if such change is adverse to the Borrower; or (v) making any other change materially adverse to the interests of the Banks.

(hh) Section 6.21 of the Credit Agreement is hereby added in its entirety to read as follows:

Section 6.21. Hydrocarbon Hedge Agreements and Interest Rate Contracts. The Borrower shall not and will not permit any Subsidiary to be a party to or in any manner liable on any Hydrocarbon Hedge Agreement or Interest Rate Contract except:

(a) Hydrocarbon Hedge Agreements with the purpose and effect of hedging prices on Hydrocarbons that are (i) consistent in all material respects with the Borrower's risk management policies and historical practices and (ii) not speculative in nature.

(b) Interest Rate Contracts with the purpose and effect of fixing interest rates on a principal amount of indebtedness of the Borrower that is accruing interest at a variable rate that are (i) consistent with the Borrower's risk management policies and historical practices and (ii) not speculative in nature; and

(c) Except for the Collateral under the Security Documents with respect to the Obligations, no Hydrocarbon Hedge Agreement or Interest Rate Contract maintained with any Bank or any Affiliate of a Bank shall require the Borrower or any Subsidiary to put up money, assets or other security against the event of its nonperformance prior to actual default by the Borrower or any Subsidiary in performing its obligations. No documents evidencing a Hydrocarbon Hedge Agreement or Interest Rate Contract maintained with any Bank or any Affiliate of a Bank shall be amended or modified in any way to advantage a counterparty thereto without amending or modifying all Hydrocarbon Hedge Agreements or Interest Rate Contracts (as applicable) maintained with any Bank or any Affiliate of a Bank to equally advantage such other counterparties.

(ii) A new paragraph is added to the end of Section 7.06 of the Credit Agreement to read in its entirety as follows:

Following the application of proceeds pursuant to the first five clauses contained in this Section 7.06, but before any surplus is paid over to the Borrower, the Administrative Agent shall apply proceeds to the ratable payment of all other Obligations which relate to any Cash Management Agreement between the Borrower or any Subsidiary and a Cash Management Bank and which are owing to the Administrative Agent, the Collateral Agent, the Banks and their Affiliates.

(jj) Section 8.12 of the Credit Agreement is hereby added in its entirety to read as follows:

Section 8.12. Cash Management Agreements. The benefit of the Security Documents and of the provisions of this Agreement relating to any collateral securing the Obligations shall also extend to and be available to those Banks or their Affiliates which are counterparties to any Cash Management Agreement with the Borrower or any of its Subsidiaries and are parties to the Intercreditor Agreement on a pro rata basis in respect of any obligations of the Borrower or any of its Subsidiaries which arise under any such Cash Management Agreement that is in effect while such Person or its Affiliate is a Bank, but only while such Person or its Affiliate is a Bank, including any Cash Management Agreements between such Persons in existence prior to the Sixth Amendment Effective Date. No Bank or any Affiliate of a Bank shall have any voting rights under any

Credit Document as a result of the existence of obligations owed to it under any such Cash Management Agreements.

(kk) Section 9.18 of the Credit Agreement is hereby restated in its entirety as follows:

Section 9.18. [Intentionally Omitted]

(ll) Exhibit B to the Credit Agreement is hereby substituted with the Exhibit B attached hereto for all purposes under the Credit Agreement and any reference to Exhibit B in the Credit Documents shall refer to the Exhibit B attached hereto.

Section 2. Consent. The Banks executing this Amendment hereby consent to the execution of the Letter Amendment No. 4 to Amended and Restated Note Purchase Agreement among the Borrower, the Guarantors and the holders of the Note Obligations party thereto in substantially the form of Exhibit A attached hereto. Such consent is limited to the extent described herein and shall not be construed as a consent to any other amendment or modification of the Note Agreement or any document otherwise related thereto that is otherwise prohibited by the terms of the Credit Agreement, the Intercreditor Agreement or any other Credit Document.

Section 3. Conditions Precedent. This Amendment shall become effective as of the date first set forth above upon the satisfaction of the following conditions precedent:

(a) The Administrative Agent shall have received each of the following:

(1) this Amendment, duly executed by the Borrower, the Majority Banks, the Administrative Agent and the Collateral Agent;

(2) the acknowledgment attached to this Amendment, duly executed by each Guarantor;

(3) an executed copy of the Letter Amendment No. 4 to Amended and Restated Note Purchase Agreement on terms and conditions reasonably satisfactory to the Majority Banks, including but not limited to the consent of the Required Holders of this Amendment (as such term is defined in the Note Agreement);

(4) an executed copy of an amendment to the Intercreditor Agreement;

(5) such certificates of resolutions or other action, incumbency certificates and/or other certificates of Responsible Officers of the Borrower and each Guarantor as the Administrative Agent may reasonably require evidencing the identity, authority and capacity of each Responsible Officer thereof authorized to act as a Responsible Officer in connection with this Amendment and the other Credit Documents to which the Borrower and such Guarantor is a party or is to be a party;

(6) such documents and certifications as the Administrative Agent may reasonably require to evidence that the Borrower and each Guarantor is duly organized or formed, and that the Borrower and each Guarantor is validly existing, in good standing and qualified to engage in business;

(7) the Administrative Agent shall have received payment or evidence of payment of (i) all reasonable fees and expenses owed by the Borrower to the Administrative Agent including, without limitation, the reasonable fees and expenses of Winstead PC, counsel to the Administrative Agent and FTI Consulting, Inc., advisor to the Administrative Agent; and (ii) all other fees agreed to be paid by the Borrower;

(8) the Administrative Agent shall have received for the account of each Bank executing this Amendment an amendment fee equal to 0.50% multiplied by such Bank's Commitment;

(9) the Administrative Agent shall have received a completed and duly executed Perfection Certificate (the 'Perfection Certificate") in form and substance reasonably satisfactory to the Administrative Agent; and

(10) the Administrative Agent shall have received such other documents, instruments and certificates as reasonably requested by the Administrative Agent and the Banks.

(b) The representations and warranties set forth in Section 4 of this Amendment shall be true and correct on and as of the date hereof.

Section 4. Representations and Warranties. The Borrower represents and warrants to the Banks, the Administrative Agent and the Collateral Agent as set forth below:

(a) The execution, delivery and performance by the Borrower of this Amendment are within the Borrower's legal powers, have been duly authorized by all necessary partnership action and do not (i) contravene the Borrower Partnership Agreement, (ii) violate any applicable Governmental Rule, the violation of which could reasonably be expected to have a Material Adverse Effect, (iii) conflict with or result in the breach of, or constitute a default under, any loan agreement, indenture, mortgage, deed of trust or lease, or any other contract or instrument binding on or affecting the Borrower or any Subsidiary or any of their respective properties, the conflict, breach or default of which could reasonably be expected to have a Material Adverse Effect, or (iv) result in or require the creation or imposition of any Lien upon or with respect to any of the properties of the Borrower, other than Liens permitted by the Credit Agreement.

(b) No Governmental Action is required for the due execution, delivery or performance by the Borrower of this Amendment.

(c) Assuming due execution and delivery by the Majority Banks, the Administrative Agent and the Collateral Agent, this Amendment constitutes legal, valid and binding obligations of the Borrower, enforceable against the Borrower in accordance

with its terms, except as the enforceability thereof may be limited by bankruptcy, insolvency, moratorium, reorganization or other similar laws affecting creditors' rights generally or by general principles of equity (regardless of whether such enforceability is considered in any proceeding in law or in equity).

(d) The execution, delivery and performance of this Amendment do not adversely affect the enforceability of any Lien of the Security Documents.

(e) The quarterly and annual financial statements most recently delivered to the Banks pursuant to Sections 5.01(c) and (d) of the Credit Agreement fairly present in all material respects the Consolidated financial condition of the Borrower and its Subsidiaries as of the respective dates thereof and the Consolidated results of the operations of the Borrower and its Subsidiaries for the respective fiscal periods ended on such dates, all in accordance with GAAP applied on a consistent basis (subject to normal year-end audit adjustments and the absence of footnotes in the case of the quarterly financial statements). Since September 30, 2008, no Material Adverse Effect has occurred. The Borrower and its Subsidiaries have no material contingent liabilities except as disclosed in such financial statements or the notes thereto.

(f) There is no pending or, to the knowledge of the Borrower, threatened action or proceeding affecting the Borrower or any Subsidiary before any Governmental Person, referee or arbitrator that could reasonably be expected to have a Material Adverse Effect.

(g) The representations and warranties made by the Borrower and the Guarantors contained in Article IV of the Credit Agreement and in each of the other Credit Documents are true and correct in all material respects on and as of the date hereof, as though made on and as of such date, other than any such representations or warranties that, by the their terms, refer to a specific date, in which case as of such specific date.

(h) No event has occurred and is continuing, or would result from the effectiveness of this Amendment, which constitutes a Default.

(i) As of the date hereof, the Borrower has no (a) Material Subsidiaries other than those listed on Schedule 6(a) and (b) non-Material Subsidiaries other than those listed on Schedule 6(b).

Section 5. Reference to and Effect on the Credit Agreement.

(a) On and after the effective date of this Amendment each reference in the Credit Agreement to "this Agreement," "hereunder," "hereof," "herein" or words of like import shall mean and be a reference to the Credit Agreement, and each reference in the other Credit Documents to "the Credit Agreement," "thereunder," "thereof," "therein" or words of like import referring to the Credit Agreement, shall mean and be a reference to the Credit Agreement as amended by this Amendment.

(b) Except as specifically amended above, the Credit Agreement and the other Credit Documents shall remain in full force and effect and are hereby ratified and confirmed. Without limiting the generality of the foregoing, the Security Documents and all of the Collateral described therein do and shall continue to secure the payment of all obligations stated to be secured thereby under the Credit Documents.

(c) Except as expressly set forth herein, the execution, delivery and effectiveness of this Amendment shall not operate as a waiver of any right, power or remedy of the Administrative Agent or any Bank under any of the Credit Documents or constitute a waiver of any provision of any of the Credit Documents.

Section 6. Execution in Counterparts. This Amendment may be executed in any number of counterparts and by the parties hereto in separate counterparts, each which when so executed and delivered shall be deemed to be an original and all of which when taken together shall constitute but one and the same instrument. Delivery of an executed counterpart of a signature page to this Amendment by telecopier shall be effective as delivery of an originally executed counterpart of this Amendment.

Section 7. Governing Law; Binding Effect. This Amendment shall be governed by, and construed and enforced in accordance with, the laws of the State of Texas, and shall be binding upon the Borrower, the Administrative Agent, the Collateral Agent, each Bank and their respective successors and assigns.

Section 8. Costs and Expenses. The Borrower agrees to pay on demand all costs and expenses of the Administrative Agent in connection with the preparation, execution and delivery of this Amendment and the other instruments and documents to be delivered hereunder, including the reasonable fees and out-of-pocket expenses of counsel for the Administrative Agent with respect thereto and with respect to advising the Administrative Agent as to its rights and responsibilities hereunder and thereunder.

Section 9. Release. As a material part of the consideration for the Administrative Agent and the Banks entering into this Amendment, the Borrower and each Guarantor executing this Amendment (collectively "Releasor") agree as follows (the "Release Provision"):

(a) Releasor hereby releases and forever discharges the Administrative Agent and each Bank and the Administrative Agent's and each Bank's predecessors, successors, assigns, officers, managers, directors, shareholders, employees, agents, attorneys, representatives, parent corporations, subsidiaries, and affiliates (hereinafter all of the above collectively referred to as "Bank Group") jointly and severally from any and all claims, counterclaims, demands, damages, suits, actions, and causes of action of any nature whatsoever occurring prior to the date hereof, including, without limitation, all claims, demands, and causes of action for contribution and indemnity, whether arising at law or in equity, presently possessed, whether known or unknown, whether liability be direct or indirect, liquidated or unliquidated, presently accrued, whether absolute or contingent, foreseen or unforeseen, and whether or not heretofore asserted ("Claims"), which Releasor may have or claim to have against any of Bank Group, in each case to the extent such Claims arose out of or relate to the Credit Agreement or the transactions

contemplated thereby; except, as to any member of the Bank Group, to the extent that any such Claims results from any of gross negligence or willful misconduct of that member.

(b) Releasor agrees not to sue any of Bank Group or in any way assist any other person or entity in suing Bank Group with respect to any claim released herein. The Release Provision may be pleaded as a full and complete defense to, and may be used as the basis for an injunction against, any action, suit, or other proceeding which may be instituted, prosecuted, or attempted in breach of the release contained herein.

(c) Releasor acknowledges, warrants, and represents to Bank Group that:

(1) Releasor has read and understands the effect of the Release Provision. Releasor has had the assistance of independent counsel of its own choice, or has had the opportunity to retain such independent counsel, in reviewing, discussing, and considering all the terms of the Release Provision; and if counsel was retained, counsel for Releasor has read and discussed the Release Provision with Releasor. Before execution of this Amendment, Releasor has had adequate opportunity to make whatever investigation or inquiry it may deem necessary or desirable in connection with the subject matter of the Release Provision.

(2) Releasor is not acting in reliance on any representation, understanding, or agreement not expressly set forth herein. Releasor acknowledges that Bank Group has not made any representation with respect to the Release Provision except as expressly set forth herein.

(3) Releasor has executed the Release Provision with the understanding that the Banks are relying on it in agreeing to enter into this Agreement and that the Banks would not execute this Amendment unless Releasor executed the Release Provision.

(4) Releasor is the sole owner of the claims released by the Release Provision, and Releasor has not heretofore conveyed or assigned any interest in any such claims to any other person or entity (other than the conveyance pursuant to the Security Documents)..

(d) Releasor understands that the Release Provision was a material consideration in the agreement of the Administrative Agent and each Bank to enter into this Amendment.

(e) It is the express intent of Releasor that the release and discharge set forth in the Release Provision be construed strictly in accordance with its terms.

(f) If any term, provision, covenant, or condition of the Release Provision is held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the remainder of the provisions shall remain in full force and effect.

THIS WRITTEN AMENDMENT AND THE CREDIT DOCUMENTS REPRESENT THE FINAL AGREEMENT AMONG THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES.

THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.

[Remainder of this page blank; signature pages follow]

Executed as of the date first set forth above.

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ Michael Garberding
Name: MICHAEL GARBERDING
Title: VICE PRESIDENT — FINANCE

Each of the undersigned, as guarantors under the Second Amended and Restated Subsidiary Guaranty dated as of November 1, 2005 (the "Guaranty"), hereby (a) consents to this Amendment, and (b) confirms and agrees that the Guaranty is and shall continue to be in full force and effect and is ratified and confirmed in all respects, except that, on and after the effective date of the Amendment each reference in the Guaranty to "the Credit Agreement," "thereunder," "thereof," "therein" or any other expression of like import referring to the Credit Agreement shall mean and be a reference to the Credit Agreement as modified by this Amendment.

CROSSTEX ENERGY SERVICES, L.P.

By: Crosstex Operating GP, LLC,
its general partner

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

CROSSTEX OPERATING GP, LLC
CROSSTEX ENERGY SERVICES GP, LLC
CROSSTEX LIG, LLC
CROSSTEX TUSCALOOSA, LLC
CROSSTEX LIG LIQUIDS, LLC
CROSSTEX PROCESSING SERVICES, LLC
CROSSTEX PELICAN, LLC

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

CROSSTEX ACQUISITION MANAGEMENT, L.P.
CROSSTEX MISSISSIPPI PIPELINE, L.P.
CROSSTEX ALABAMA GATHERING SYSTEM, L.P.
CROSSTEX MISSISSIPPI INDUSTRIAL GAS SALES, L.P.
CROSSTEX GULF COAST TRANSMISSION LTD.
CROSSTEX GULF COAST MARKETING LTD.
CROSSTEX CCNG GATHERING LTD.
CROSSTEX CCNG PROCESSING LTD.
CROSSTEX CCNG TRANSMISSION LTD.
CROSSTEX TREATING SERVICES, L.P.
CROSSTEX NORTH TEXAS PIPELINE, L.P.
CROSSTEX NORTH TEXAS GATHERING, L.P.
CROSSTEX NGL MARKETING, L.P.
CROSSTEX NGL PIPELINE, L.P.

By: Crosstex Energy Services GP, LLC,
general partner of each above limited partnership

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

SABINE PASS PLANT FACILITY JOINT VENTURE

By: Crosstex Processing Services, LLC,
as general partner, and

By: Crosstex Pelican, LLC, as general partner

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

BANK OF AMERICA, N.A.,
as Administrative Agent, Collateral Agent,
a Bank and an Issuing Bank

By: /s/ Tyler D. Levings
Name: Tyler D. Levings
Title: Senior Vice President

THE BANK OF NOVA SCOTIA

By: /s/ David G. Mills
Name: David G. Mills
Title: Managing Director

BANK OF SCOTLAND plc, New York Branch

By: /s/ Karen Weich
Name: Karen Weich
Title: Vice President

BAYERISCHE HYPO-UND VEREINSBANK AG, NEW YORK BRANCH

By: /s/ Yoram Dankner
Name: Yoram Dankner
Title: Managing Director

By: /s/ Miriam Trautmann
Name: Miriam Trautmann
Title: Director

BMO CAPITAL MARKETS FINANCING, INC.

By: /s/ Tom McGraw
Name: Tom McGraw
Title: Managing Director

BNP PARIBAS

By: /s/ Gregory E. George
Name: GREGORY E. GEORGE
Title: Managing Director

By: /s/ Larry Robinson
Name: Larry Robinson
Title: Director

CITIBANK, N.A.

By: /s/ Amy Pincu
Name: Amy Pincu
Title: Vice President

COMERICA BANK

By: /s/ Peter L. Sefzik
Name: PETER L. SEFZIK
Title: SENIOR VICE PRESIDENT

COMPASS BANK

By: /s/ Greg Determann
Name: Greg Determann
Title: Vice President

COOPERATIVE CENTRALE RAIFFEISEN-BOERENLEENBANK
BA "RABOBANK NEDERLAND" NEW YORK BRANCH

By: /s/ Jeff P. Geisbauer
Name: Jeff P. Geisbauer
Title: Vice President

By: /s/ Rebecca O. Morrow
Name: Rebecca O. Morrow
Title: Executive Director

FORTIS CAPITAL CORP.

By: /s/ Darrell Holley
Name: Darrell Holley
Title: Managing Director

By: /s/ Casey Lowary
Name: Casey Lowary
Title: Director

GUARANTY BANK

By: /s/ Christopher S. Parada
Name: Christopher S. Parada
Title: Senior Vice President

JPMORGAN CHASE BANK, N.A.

By: /s/ John Runger
Name: John Runger
Title: Managing Director

KEY BANK, N.A.

By: /s/ Todd Coker
Name: Todd Coker
Title: AVP

MIZUHO CORPORATE BANK, LTD.

By: /s/ Leon Mo
Name: Leon Mo
Title: Senior Vice President

NATIONAL CITY BANK

By: /s/ Tom Gurbach
Name: Tom Gurbach
Title: Vice President

NATIXIS

By: /s/ Daniel Payer
Name: Daniel Payer
Title: Director

By: /s/ Louis P. Laville, III
Name: Louis P. Laville, III
Title: Managing Director

ROYAL BANK OF CANADA

By: /s/ Jason S. York
Name: Jason S. York
Title: Authorized Signatory

SCOTIABANC INC.

By: /s/ J. F. Todd
Name: J. F. Todd
Title: Managing Director

SOCIETE GENERALE

By: /s/ Stephen W. Warfel
Name: Stephen W. Warfel
Title: Managing Director

STERLING BANK

By: /s/ Jeff Forbis
Name: Jeff Forbis
Title: Senior Vice President

SUMITOMO MITSUI BANKING CORPORATION

By: /s/ William Ginn
Name: William Ginn
Title: General Manager

SUNTRUST BANK

By: /s/ Janet R. Naifeh
Name: Janet R. Naifeh
Title: Senior Vice President

U.S. BANK NATIONAL ASSOCIATION

By: /s/ Daria Mahoney
Name: Daria Mahoney
Title: Vice President

SCHEDULE 6(a)

Material Subsidiaries

Crosstex Energy Services, L.P. (DE domestic)
Crosstex Operating GP, LLC (DE domestic)
Crosstex Energy Services GP, LLC (DE domestic)
Crosstex LIG, LLC (LA domestic)
Crosstex Tuscaloosa, LLC (LA domestic)
Crosstex LIG Liquids, LLC (LA domestic)
Crosstex Acquisition Management, L.P. (DE domestic)
Crosstex Mississippi Pipeline, L.P. (DE domestic)
Crosstex Alabama Gathering System, L.P. (DE domestic)
Crosstex Mississippi Industrial Gas Sales, L.P. (DE domestic)
Crosstex Gulf Coast Transmission Ltd. (TX domestic)
Crosstex Gulf Coast Marketing Ltd. (TX domestic)
Crosstex CCNG Gathering Ltd. (TX domestic)
Crosstex CCNG Processing Ltd. (TX domestic)
Crosstex CCNG Transmission Ltd. (TX domestic)
Crosstex Treating Services, L.P. (DE domestic)
Crosstex North Texas Pipeline, L.P. (TX domestic)
Crosstex North Texas Gathering, L.P. (TX domestic)
Crosstex NGL Pipeline, L.P. (TX domestic)
Crosstex NGL Marketing, L.P. (TX domestic)
Crosstex Processing Services, LLC (DE domestic)
Crosstex Pelican, LLC (DE domestic)
Sabine Pass Plant Facility Joint Venture (a TX general partnership)

SCHEDULE 6(b)

Non-Material Subsidiaries

Crosstex Louisiana Energy, L.P. (Delaware domestic)
LIG Chemical GP, LLC (Delaware domestic)
LIG Chemical, L.P. (Delaware domestic)
LIG Liquids Holdings, L.P. (Delaware domestic)
Crosstex Midstream Services, L.P. (Delaware domestic)
Crosstex Mississippi Gathering, L.P. (Delaware domestic)
Crosstex Louisiana Gathering, LLC (Louisiana domestic)

**Schedule 6(b) to Sixth Amendment to Fourth Amended and Restated Credit Agreement and Consent**

EXHIBIT A

Letter Amendment No. 4 to Amended and Restated Note Purchase Agreement

Filed separately with the Commission.

**Exhibit A to Sixth Amendment to Fourth Amended and Restated Credit Agreement and Consent**

EXHIBIT B

EXHIBIT B

**NOTICE OF BORROWING**

_____, 20__

Bank of America, N.A., as Administrative Agent
Mail Code: NC1-001-15-04
One Independence Center
101 N. Tryon St.
Charlotte, NC 28255-0001
Attn: Edwina Champion, Credit Services

Re: Crosstex Energy

Ladies and Gentlemen:

The undersigned, Crosstex Energy, L.P., a Delaware limited partnership, refers to the Fourth Amended and Restated Credit Agreement dated as of November 1, 2005 (the "Credit Agreement") among the undersigned, the Banks referred to therein, Bank of America, N.A., as administrative agent (the "Administrative Agent") for said Banks, Union Bank of California, N.A. and SunTrust Bank, as co-syndication agents, and Bank of Montreal d/b/a Harris Nesbitt and Wachovia Bank, National Association, as co-documentation agents. Terms defined in the Credit Agreement and not otherwise defined herein have the same respective meanings when used herein.

Pursuant to Section 2.02(a) of the Credit Agreement, the undersigned hereby requests a Borrowing under the Credit Agreement and in that connection sets forth below the information relating to such Borrowing (the "Proposed Borrowing"), as required by Section 2.02(a) of the Credit Agreement.

The Business Day of the Proposed Borrowing is ___, 20_.

The Proposed Borrowing will be composed of **[Reference Rate Advances] [Eurodollar Rate Advances]**.

The aggregate amount of the Proposed Borrowing is $_____.

**[The initial Interest Period for the Eurodollar Rate Advances is _____month[s].]**

The officer of Crosstex Energy GP, LLC, the general partner of the General Partner signing this notice on behalf of the General Partner and the Borrower hereby certifies (as an officer of Crosstex Energy GP, LLC and not in his/her individual capacity) that the following statements are true on the date hereof and will be true on the date of the Proposed Borrowing:

the representations and warranties contained in each Credit Document are correct in all material respects, before and after giving effect to the Proposed Borrowing and to

the application of the proceeds thereof, as though made on and as of such date (other than any such representations and warranties that, by their terms, refer to a specific date, in which case as of such specific date);

no event has occurred and is continuing, or would result from the Proposed Borrowing or from the application of the proceeds thereof, that constitutes a Default; and

after giving effect to the receipt of the proceeds of the requested Borrowing, and the anticipated cash receipts and cash uses of the Borrower and its Subsidiaries on the date of the applicable Borrowing and the next Business Day, the aggregate balances in the Cash Management Accounts on the next Business Day shall not be in excess of $25,000,000.

Very truly yours,

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC,
its general partner

By: _____
Name: _____
Title: _____

**Exhibit B to Sixth Amendment to Fourth Amended and Restated Credit Agreement and Consent**

Exhibit 10.11

**EXECUTION COPY**

**LETTER AMENDMENT NO. 4**

**to**

**AMENDED AND RESTATED**
**NOTE PURCHASE AGREEMENT**

As of February 27, 2009

To: Each of the Holders listed
on Exhibit A attached hereto

Ladies and Gentlemen:

We refer to the Amended and Restated Note Purchase Agreement, dated as of March 31, 2005, as amended as of June 22, 2005, November 1, 2005, March 13, 2006 and June 29, 2006, as Amended and Restated as of July 25, 2006 and as amended by Letter Amendment No. 1 to Amended and Restated Note Purchase Agreement, dated as of March 30, 2007, Letter Amendment No. 2 to Amended and Restated Note Purchase Agreement, dated as of September 19, 2007, and Waiver and Letter Amendment No. 3 to Amended and Restated Note Purchase Agreement, dated as of November 7, 2008 (as so amended and restated and amended, the **"Agreement"**), among Crosstex Energy, L.P., a Delaware limited partnership (the **"Company"**), on one hand, and each of you (the **"Holders"**), on the other hand. Unless otherwise defined in this Waiver and Letter Amendment No. 4 to Amended and Restated Note Purchase Agreement (this "**Amendment**"), the terms defined in the Agreement shall be used herein as therein defined.

The Company has requested that the Holders agree to make certain amendments to the Agreement as hereinafter provided. Subject to the terms and conditions specified herein, and provided that the Company agrees to certain amendments to the Agreement and the Notes set forth below, the Holders have indicated their willingness to make such amendments requested by the Company as more particularly set forth herein.

Accordingly, subject to satisfaction of the conditions set forth in paragraph 3 hereof, and in reliance on the representations and warranties of the Company set forth in paragraph 2 hereof, the Holders hereby agree with the Company to amend the Agreement and the Notes as provided in paragraph 1 below effective as of the Amendment No. 4 Effective Date (as defined in paragraph 3 below).

**1. Amendments.**

(a) **Paragraph 1A. Authorization of Series A Notes; Exhibit A-1; Series A Notes.** Paragraph 1A of the Agreement, Exhibit A-1 to the Agreement and each outstanding Series A Note is hereby amended to change the interest rate thereof from "7.45%" to "9.45% plus any Additional Interest" in each place where it appears therein.

(b) **Paragraph 1B. Authorization of Series B Notes; Exhibit A-2; Series B Notes.** Paragraph 1B of the Agreement, Exhibit A-2 to the Agreement and each outstanding Series B Note is hereby amended to change the interest rate thereof from "7.38%" to "9.38% plus any Additional Interest" in each place where it appears therein.

(c) **Paragraph 1C. Authorization of Series C Notes, Exhibit A-3; Series C Notes.** Paragraph 1C of the Agreement, Exhibit A-3 to the Agreement and each outstanding Series C Note is hereby amended to change the interest rate thereof from "7.46%" to "9.46% plus any Additional Interest" in each place where it appears therein.

(d) **Paragraph 1D. Authorization of Series D Notes, Exhibit A-4; Series D Notes.** Paragraph 1D of the Agreement, Exhibit A-4 to the Agreement and each outstanding Series D Note is hereby amended to change the interest rate thereof from "6.73%" to "8.73% plus any Additional Interest" in each place where it appears therein.

(e) **Paragraph 1E. Authorization of Series E Notes; Exhibit A-5; Series E Notes.** Paragraph 1E of the Agreement, Exhibit A-5 to the Agreement and each outstanding Series E Note is hereby amended to change the interest rate thereof from "6.82%" to "8.82% plus any Additional Interest" in each place where it appears therein.

(f) **Paragraph 1F. Authorization of Series F Notes; Exhibit A-6; Series F Notes.** Paragraph 1F of the Agreement, Exhibit A-6 to the Agreement and each outstanding Series F Note is hereby amended to change the interest rate thereof from "7.46%" to "9.46% plus any Additional Interest" in each place where it appears therein and by amending the first sentence of the second paragraph of paragraph 1F of the Agreement in its entirety to read as follows:

"The term **"Notes"** as used in this Agreement shall mean any Series A Note, any Series B Note, any Series C Note, any Series D Note, any Series E Note, any Series F Note, any Additional Note and any PIK Note."

(g) **Paragraphs 1H and 1I. Authorization of Issue of PIK Notes; Additional Interest.** New paragraphs 1H and 1I are added to the Agreement to read as follows:

"1H. **PIK Notes.**

1H(1) **Series A PIK Notes.** The Company will authorize the issue of its Senior Secured PIK Notes, Series A (the '**Series A PIK Notes**") in an amount sufficient to evidence the aggregate amounts of Additional Interest that it may from time to time pay on the Series A Notes by adding such Additional Interest to the principal of the Series A PIK Notes pursuant to paragraph 1I(i) hereof or this paragraph 1H(1) and any Yield-Maintenance Amount that may be paid with respect to the Series A Notes by adding such Yield-Maintenance Amount to the principal of the Series A PIK Notes as provided in this Agreement, to be dated the date of issue thereof, to mature on the PIK Note Maturity Date, to accrue interest on the unpaid balance thereof from the date thereof until the principal thereof shall have become due and payable at the rate of 9.45% per annum plus any Additional Interest, and on the occurrence and during the continuation of an Event of Default at the rate specified therein and are substantially in the form of

Exhibit A-1-B hereto. Interest on any principal of any Series A PIK Note due before the date such principal is due (whether on the PIK Note Maturity Date, by acceleration, optional or mandatory prepayment or otherwise) shall be paid by adding such interest to the principal balance of such Series A PIK Note. The term **"Series A PIK Notes"** as used herein shall include each Series A PIK Note delivered pursuant to any provision of this Agreement and each Series A PIK Note delivered in substitution or exchange of any such Series A PIK Note pursuant to any such provision.

1H(2) **Series B PIK Notes.** The Company will authorize the issue of its Senior Secured PIK Notes, Series B (the '**Series B PIK Notes**") in an amount sufficient to evidence the aggregate amounts of Additional Interest that it may from time to time pay on the Series B Notes by adding such Additional Interest to the principal of the Series B PIK Notes pursuant to paragraph 1I(i) hereof or this paragraph 1H(2) and any Yield-Maintenance Amount that may be paid with respect to the Series B Notes by adding such Yield-Maintenance Amount to the principal of the Series B PIK Notes as provided in this Agreement, to be dated the date of issue thereof, to mature on the PIK Note Maturity Date, to accrue interest on the unpaid balance thereof from the date thereof until the principal thereof shall have become due and payable at the rate of 9.38% per annum plus any Additional Interest, and on the occurrence and during the continuation of an Event of Default at the rate specified therein and are substantially in the form of Exhibit A-2-B hereto. Interest on any principal of any Series B PIK Note due before the date such principal is due (whether on the PIK Note Maturity Date, by acceleration, optional or mandatory prepayment or otherwise) shall be paid by adding such interest to the principal balance of such Series B PIK Note. The term **"Series B PIK Notes"** as used herein shall include each Series B PIK Note delivered pursuant to any provision of this Agreement and each Series B PIK Note delivered in substitution or exchange of any such Series B PIK Note pursuant to any such provision.

1H(3) **Series C PIK Notes.** The Company will authorize the issue of its Senior Secured PIK Notes, Series C (the '**Series C PIK Notes**") in an amount sufficient to evidence the aggregate amounts of Additional Interest that it may from time to time pay on the Series C Notes by adding such Additional Interest to the principal of the Series C PIK Notes pursuant to paragraph 1I(i) hereof or this paragraph 1H(3) and any Yield-Maintenance Amount that may be paid with respect to the Series C Notes by adding such Yield-Maintenance Amount to the principal of the Series C PIK Notes as provided in this Agreement, to be dated the date of issue thereof, to mature on the PIK Note Maturity Date, to accrue interest on the unpaid balance thereof from the date thereof until the principal thereof shall have become due and payable at the rate of 9.46% per annum plus any Additional Interest, and on the occurrence and during the continuation of an Event of Default at the rate specified therein and are substantially in the form of Exhibit A-3-B hereto. Interest on any principal of any Series C PIK Note due before the date such principal is due (whether on the PIK Note Maturity Date, by acceleration, optional or mandatory prepayment or otherwise) shall be paid by adding such interest to the principal balance of such Series C PIK Note. The term **"Series C PIK Notes"** as used herein shall include each Series C PIK Note delivered pursuant to any provision of this Agreement and each Series C PIK Note delivered in substitution or exchange of any such Series C PIK Note pursuant to any such provision.

1H(4) **Series D PIK Notes.** The Company will authorize the issue of its Senior Secured PIK Notes, Series D (the '**Series D PIK Notes**") in an amount sufficient to evidence the aggregate amounts of Additional Interest that it may from time to time pay on the Series D Notes by adding such Additional Interest to the principal of the Series D PIK Notes pursuant to paragraph 1I(i) hereof or this paragraph 1H(4) and any Yield-Maintenance Amount that may be paid with respect to the Series D Notes by adding such Yield-Maintenance Amount to the principal of the Series D PIK Notes as provided in this Agreement, to be dated the date of issue thereof, to mature on the PIK Note Maturity Date, to accrue interest on the unpaid balance thereof from the date thereof until the principal thereof shall have become due and payable at the rate of 8.73% per annum plus any Additional Interest, and on the occurrence and during the continuation of an Event of Default at the rate specified therein and are substantially in the form of Exhibit A-4-B hereto. Interest on any principal of any Series D PIK Note due before the date such principal is due (whether on the PIK Note Maturity Date, by acceleration, optional or mandatory prepayment or otherwise) shall be paid by adding such interest to the principal balance of such Series D PIK Note. The term **"Series D PIK Notes"** as used herein shall include each Series D PIK Note delivered pursuant to any provision of this Agreement and each Series D PIK Note delivered in substitution or exchange of any such Series D PIK Note pursuant to any such provision.

1H(5) **Series E PIK Notes.** The Company will authorize the issue of its Senior Secured PIK Notes, Series E (the '**Series E PIK Notes**") in an amount sufficient to evidence the aggregate amounts of Additional Interest that it may from time to time pay on the Series E Notes by adding such Additional Interest to the principal of the Series E PIK Notes pursuant to paragraph 1I(i) hereof or this paragraph 1H(5) and any Yield-Maintenance Amount that may be paid with respect to the Series E Notes by adding such Yield-Maintenance Amount to the principal of the Series E PIK Notes as provided in this Agreement, to be dated the date of issue thereof, to mature on the PIK Note Maturity Date, to accrue interest on the unpaid balance thereof from the date thereof until the principal thereof shall have become due and payable at the rate of 8.82% per annum plus any Additional Interest, and on the occurrence and during the continuation of an Event of Default at the rate specified therein and are substantially in the form of Exhibit A-5-B hereto. Interest on any principal of any Series E PIK Note due before the date such principal is due (whether on the PIK Note Maturity Date, by acceleration, optional or mandatory prepayment or otherwise) shall be paid by adding such interest to the principal balance of such Series E PIK Note. The term **"Series E PIK Notes"** as used herein shall include each Series E PIK Note delivered pursuant to any provision of this Agreement and each Series E PIK Note delivered in substitution or exchange of any such Series E PIK Note pursuant to any such provision.

1H(6) **Series F PIK Notes.** The Company will authorize the issue of its Senior Secured PIK Notes, Series F (the '**Series F PIK Notes**") in an amount sufficient to evidence the aggregate amounts of Additional Interest that it may from time to time pay on the Series F Notes by adding such Additional Interest to the principal of the Series F PIK Notes pursuant to paragraph 1I(i) hereof or this paragraph 1H(6) and any Yield-Maintenance Amount that may be paid with respect to the Series F Notes by adding such Yield-Maintenance Amount to the principal of the Series F PIK Notes as provided in this

Agreement, to be dated the date of issue thereof, to mature on the PIK Note Maturity Date, to accrue interest on the unpaid balance thereof from the date thereof until the principal thereof shall have become due and payable at the rate of 9.46% per annum plus any Additional Interest, and on the occurrence and during the continuation of an Event of Default at the rate specified therein and are substantially in the form of Exhibit A-6-B hereto. Interest on any principal of any Series F PIK Note due before the date such principal is due (whether on the PIK Note Maturity Date, by acceleration, optional or mandatory prepayment or otherwise) shall be paid by adding such interest to the principal balance of such Series F PIK Note. The term **"Series F PIK Notes"** as used herein shall include each Series F PIK Note delivered pursuant to any provision of this Agreement and each Series F PIK Note delivered in substitution or exchange of any such Series F PIK Note pursuant to any such provision. The term **"PIK Notes"** as used in this Agreement shall mean any Series A PIK Note, any Series B PIK Note, any Series C PIK Note, any Series D PIK Note, any Series E PIK Note and any Series F PIK Note.

1I. **Additional Interest.** In addition to the stated interest payable on the Notes as set forth in paragraphs 1A through 1F hereof and in the forms of the Notes, the Company agrees to pay interest on the outstanding principal amount of each Note as follows (the additional interest payable as described in (i), (ii) and (iii) of this paragraph 1I being called "**Additional Interes**t"):

(i) For (a) the period from the Amendment No. 4 Effective Date until the end of the fiscal quarter ending March 31, 2009, and (b) any other fiscal quarter (other than a fiscal quarter immediately following a fiscal quarter as of the end of which the Leverage Ratio was less than 4.25 to 1.00, as demonstrated by evidence provided by the Company to the Holders), the Company agrees to pay interest on the Notes for such period or fiscal quarter, as the case may be, at the rate of 1.25% per annum, payable on the last day of such period or fiscal quarter, as the case may be and, with respect to any such interest on any principal amount of any Note which becomes due (whether on the PIK Maturity Date, by acceleration, optional or mandatory prepayment or otherwise), on the date such principal becomes due. Any Additional Interest payable under this paragraph 1I(i) with respect to any Note on any date before the Refinancing Date shall be payable by adding the amount thereof to the principal of the Related PIK Note, but shall otherwise be payable in cash.

(ii) (a) If the Leverage Ratio as of the end of the fiscal quarter most recently ended on or before the Refinancing Date is greater than or equal to 4.25 to 1.00, then, for the period from the Refinancing Date until the end of the first fiscal quarter ending after the Refinancing Date, and (b) for any other fiscal quarter ending after the Refinancing Date (other than a fiscal quarter immediately following a fiscal quarter as of the end of which the Leverage Ratio was less than 4.25 to 1.00, as demonstrated by evidence provided by the Company to the Holders), the Company agrees to pay interest on the Notes for such period or fiscal quarter, as the case may be, at the rate of 1.25% per annum, payable on the last day of such period or fiscal quarter, as the case may be and, with respect to any such interest on any principal amount of any Note which becomes due (whether on the maturity date of such Note, by acceleration, optional or mandatory

prepayment or otherwise), on the date such principal becomes due. Any Additional Interest payable under this paragraph 1I(ii) shall be payable in cash.

(iii) (a) If the Leverage Ratio as of the end of the fiscal quarter ending June 30, 2012 is greater than or equal to 4.00 to 1.00, then, for the fiscal quarter ending September 30, 2012, and (b) for any other fiscal quarter ending after the fiscal quarter ending September 30, 2012 (other than a fiscal quarter immediately following a fiscal quarter as of the end of which the Leverage Ratio was less than 4.00 to 1.00, as demonstrated by evidence provided by the Company to the Holders), the Company agrees to pay interest on the Notes for such fiscal quarter at the rate of 0.50% per annum, payable on the last day of such fiscal quarter and, with respect to any such interest on any principal amount of any Note which becomes due (whether on the maturity date of such Note, by acceleration, optional or mandatory prepayment or otherwise), on the date such principal becomes due; provided, however, that no Additional Interest shall be payable under this clause (iii) for any fiscal quarter for which Additional Interest is payable under clause (ii) of this paragraph 1I. Any Additional Interest payable under this paragraph 1I(iii) shall be payable in cash.

(iv) The payment of any Additional Interest at any increased rate of interest provided in this paragraph 1I shall not constitute a waiver of any Default or Event of Default."

(h) **Paragraph 4A. Required Prepayments.** Paragraph 4A of the Agreement is hereby amended and restated in its entirety as follows:

"**4A. Required Prepayments.**

(i) **Scheduled Prepayments.** The Notes of each Series shall be subject to required prepayments, if any, set forth in the Notes of such Series.

(ii) **Additional Required Prepayments.**

(a) **Asset Disposition and Recovery Event Prepayments.** Upon the receipt by the Company or any Subsidiary of any Net Cash Proceeds of any Asset Disposition or any Recovery Event (except to the extent a Reinvestment Notice shall be delivered in respect of such Recovery Event), then on the date of receipt by the Company or the applicable Subsidiary of such Net Cash Proceeds related thereto (the **"Asset Prepayment Date"**), the Company shall immediately prepay an aggregate principal amount of the Notes (other than PIK Notes) that is equal to the product of (x) the amount of the Applicable Percentage of such Net Cash Proceeds and (y) a fraction, the numerator of which is the outstanding principal amount of all Notes (other than PIK Notes) on such Asset Prepayment Date and the denominator of which is the sum of the outstanding principal amount of all Bank Obligations on such Asset Prepayment Date plus the sum of the outstanding principal amount of all Notes (other than PIK Notes) on such Asset Prepayment Date. For purposes of calculating the Net Cash Proceeds received from an Asset Disposition or from a Recovery Event,

such proceeds shall be determined as of the date of the applicable Asset Disposition or Recovery Event, whether or not received on such date, but no such amount shall be required to be applied to prepayment of the Notes pursuant to this paragraph 4A(ii)(a) until received by the applicable Person. The provisions of this paragraph 4A(ii)(a) do not constitute a consent to the consummation of any Asset Disposition not permitted by paragraph 6C(5).

(b) **Reinvestment Prepayment Date Prepayments.** On each Reinvestment Prepayment Date, the Company shall immediately prepay an aggregate principal amount of the Notes (other than PIK Notes) that is equal to the product of (x) the Reinvestment Prepayment Amount with respect to the relevant Reinvestment Event and (y) a fraction, the numerator of which is the outstanding principal amount of all Notes (other than PIK Notes) on such Reinvestment Prepayment Date and the denominator of which is the sum of the outstanding principal amount of all Bank Obligations on such Reinvestment Prepayment Date plus the sum of the outstanding principal amount of all Notes (other than PIK Notes) on such Reinvestment Prepayment Date.

(c) **Debt Issuance Prepayments.** Upon the receipt by the Company or any Subsidiary of any Net Cash Proceeds from the issuance or incurrence of any Debt for borrowed money (excluding any Debt incurred in accordance with clauses (i), (ii), (iii), (iv), (v), (vi), (vii), (viii), (ix) or (xii) of paragraph 6C(2)), then on the date of such issuance or incurrence (the **"Debt Prepayment Date"**), the Company shall immediately prepay an aggregate principal amount of the Notes (other than the PIK Notes) that is equal to the product of (x) the amount of the Applicable Percentage of such Net Cash Proceeds and (y) a fraction, the numerator of which is the outstanding principal amount of all Notes (other than PIK Notes) on such Debt Prepayment Date and the denominator of which is the sum of the outstanding principal amount of all Bank Obligations on such Debt Prepayment Date plus the sum of the outstanding principal amount of all Notes (other than PIK Notes) on such Debt Prepayment Date. The provisions of this paragraph 4A(ii)(c) do not constitute a consent to the issuance or incurrence of any Debt by the Company or any of its Subsidiaries not otherwise permitted hereunder.

(d) **Equity Issuance Prepayments.** Upon the receipt of the Company or any Subsidiary of any Net Cash Proceeds from the issuance of any Equity Interests, then on the date of receipt by the Company or the applicable Subsidiary of such Net Cash Proceeds related thereto (the **"Equity Prepayment Date"**), the Company shall immediately prepay an aggregate principal amount of the Notes (other than the PIK Notes) that is equal to the product of (x) the amount of the Applicable Percentage of such Net Cash Proceeds and (y) a fraction, the numerator of which is the outstanding principal amount of all Notes (other than PIK Notes) on such Equity Prepayment Date and the denominator of which is the sum of the outstanding principal amount of all Bank Obligations on such Equity Prepayment Date plus the sum of the outstanding principal amount of all Notes (other than PIK Notes) on such Equity Prepayment Date. The provisions of this

paragraph 4A(ii)(d) do not constitute a consent to an Equity Issuance not permitted hereunder.

(e) **Additional Required Prepayment Provisions.** Prepayment of the Notes to be prepaid pursuant to this paragraph 4A(ii) shall be at 100% of the principal amount so prepaid, together with interest accrued on the principal amount being prepaid and any Yield-Maintenance Amount with respect thereto; provided, that, no Yield-Maintenance Amount shall be due with respect to the prepayment of Notes from the Net Cash Proceeds of Recovery Events, except to the extent that the aggregate principal amount of the Notes prepaid under this paragraph 4A(ii) from the Net Cash Proceeds of Recovery Events exceeds $20,000,000. The principal amount of any Note prepaid pursuant to this paragraph 4A(ii) shall be applied and reduce the required prepayments of such Note referred to in paragraph 4A(i) hereof in the inverse order of their scheduled due dates. Notwithstanding anything to the contrary contained in this Agreement, prior to the Refinancing Date, any Yield-Maintenance Amount due and payable with respect to any such prepayment of any Note pursuant to this paragraph 4A(ii) shall be paid by adding the amount thereof to the outstanding amount of the Related PIK Note.

(f) **Certain Recovery Amounts.** To the extent that the Company or any Subsidiary receives proceeds from any Recovery Event in excess of $10,000,000, such proceeds shall be delivered to the Collateral Agent to be held as Cash Collateral for the Bank Obligations and the Obligations in accordance with the Intercreditor Agreement.

(iii) **Inability to Make Required Prepayments.** The fact that the Company does not or is unable for any reason to make any prepayment of the Notes required under this paragraph 4A at the time required, including, without limitation, because the Company is unable to borrow funds necessary to make such prepayment under the Bank Agreement, shall not prevent such failure to make such prepayment from constituting an Event of Default."

(i) **Paragraph 4D. Application of Prepayments.** Paragraph 4D of the Agreement is hereby amended and restated in its entirety as follows:

"4D. **Application of Prepayments.** Upon any partial prepayment of the Notes of any Series pursuant to paragraph 4A(i), the amount so prepaid shall be allocated to all outstanding Notes of such Series (including, for the purpose of this paragraph 4D only, all Notes prepaid or otherwise retired or purchased or otherwise acquired by the Company or any of its Subsidiaries or Affiliates other than by prepayment pursuant to paragraph 4A, 4B or 4F) in proportion to the respective outstanding principal amounts thereof. Upon any partial prepayment of the Notes pursuant to paragraph 4B, the amount to be prepaid shall be applied pro rata to all outstanding Notes of all Series according to the respective unpaid principal amounts thereof."

(j) **Paragraph 4F. Offer to Prepay Notes in the Event of Excess Cash Flow.** Paragraph 4F of the Agreement is hereby amended and restated in its entirety as follows:

"4F. **Offer to Prepay Notes in the Event of Excess Cash Flow.**

(i) **Notice of Offer to Prepay Notes.** The Company will, at least 10 days prior to each Excess Cash Flow Prepayment Date, give written notice thereof to each Holder. Such notice shall contain and constitute an offer to prepay the Notes as described in paragraph 4F(iii) and shall be accompanied by the certificate described in paragraph 4F(vi).

(ii) **Notice of Acceptance of Offer under Paragraph 4F(i).** If the Company shall at any time receive an acceptance to an offer to prepay Notes under paragraph 4F(i) from some, but not all, of the Holders, then the Company will, within two Business Days after the receipt of such acceptance, give written notice of such acceptance to each other Holder which has notified the Company that it requests to receive notices under this paragraph 4F(ii).

(iii) **Offer to Prepay Notes.** The offer to prepay Notes contemplated by paragraph 4F(i) shall be an offer to prepay, in accordance with and subject to this paragraph 4F, on the Excess Cash Flow Prepayment Date, a principal amount of the Notes (other than PIK Notes) held by each Holder (in this case only, "Holder" in respect of any Note registered in the name of a nominee for a disclosed beneficial owner shall mean such beneficial owner) that is equal to the product of (x) the Excess Cash Flow Prepayment Amount and (y) a fraction, the numerator of which is the outstanding principal amount of Notes (other than PIK Notes) held by such Holder on such Excess Cash Flow Prepayment Date and the denominator of which is the sum of the outstanding principal amount of all Bank Obligations on such Excess Cash Flow Prepayment Date plus the sum of the outstanding principal amount of all Notes (other than PIK Notes) on such Excess Cash Flow Prepayment Date.

(iv) **Acceptance.** A Holder may accept the offer to prepay made pursuant to paragraph 4F(i) by causing a notice of such acceptance to be delivered to the Company prior to the Excess Cash Flow Prepayment Date. A failure by a Holder to so respond to an offer to prepay made pursuant to this paragraph 4F prior to the Excess Cash Flow Prepayment Date shall be deemed to constitute an acceptance of such offer by such Holder.

(v) **Prepayment.** Prepayment of the Notes to be prepaid pursuant to this paragraph 4F shall be at 100% of the principal amount so prepaid, together with interest on such Notes accrued to the date of prepayment with respect to each such Note without any Yield-Maintenance Amount. The prepayment shall be made on the Excess Cash Flow Prepayment Date. The principal amount of any Note prepaid pursuant to this paragraph 4F shall be applied and reduce the required prepayments of such Note referred to in paragraph 4A(i) hereof in the inverse order of their scheduled due dates.

(vi) **Officer's Certificate.** Each offer to prepay the Notes pursuant to this paragraph 4F shall be accompanied by a certificate, executed by a Responsible Officer of the Company and dated the date of such offer, specifying (i) the Excess Cash Flow Prepayment Date, (ii) the date that such offer is made pursuant to this paragraph 4F, (iii) the principal amount of each Note offered to be prepaid, (iv) the interest that would be due on each Note offered to be prepaid, (v) that the conditions of this paragraph 4F have been fulfilled, and (vi) in reasonable detail, the calculation of the Excess Cash Flow relating to such Excess Cash Flow Prepayment Date and the details of the calculation of the amount of the Notes offered to be prepaid."

(k) **Paragraph 5A. Reporting Requirements.** Paragraph 5A of the Agreement is hereby amended by (i) deleting the "and" at the end of clause (x), (ii) amending and restating clause (xi), (iii) adding new clauses (xii), (xiii), (xiv) and (xv) at the end thereof, (iv) deleting the second to the last paragraph therein and (v) amending and restating the last paragraph in its entirety as follows:

"(xi) Monthly Financials, Operating Report and Cash Flow Budget. As soon as available and in any event within 35 days after the end of each month of each calendar year of the Company, commencing with the month ending February 28, 2009, (a) an unaudited Consolidated balance sheet of the Company and its Subsidiaries as of the end of such month and unaudited Consolidated statements of operations, changes in partners' capital and cash flows of the Company and its Subsidiaries for the period commencing at the end of the preceding fiscal year and ending with the end of such month, setting forth in each case in comparative form the corresponding figures for the corresponding period of the preceding fiscal year and the actual to budgeted performance, all in reasonable detail and duly certified (subject to normal year-end audit adjustments and the absence of footnotes) by the chief financial officer, chief accounting officer or Vice President — Finance of the Ultimate General Partner as having been prepared in accordance with GAAP, together with a certificate of said officer stating that no Default or Event of Default has occurred and is continuing or, if a Default or an Event of Default has occurred and is continuing, a statement as to the nature thereof and the action that the Company proposes to take with respect thereto, (b) an operating report containing the information specified on Schedule 5A hereto and (c) a rolling 13 week cash flow budget in form mutually satisfactory to the Required Holder(s) and the Company, including forecasts of receipts and disbursements prepared by management of the Company and a comparison of actual to budgeted performance;

(xii) Interests in Real Property. As soon as available, but in any event (a) within 60 days after the end of each fiscal quarter of each fiscal year of the Company, commencing with the fiscal quarter ending March 31, 2009, a summary of substantially all new real property interests (including owned and leased properties, easements and other property interests) acquired and recorded by the Company or any Subsidiary ("**Newly Acquired Real Property Report**") during the preceding fiscal quarter and (b) within 90 days after the Amendment No. 4 Effective Date, a report on the progress of completing the post-closing requirements set forth in paragraph 5W;

(xiii) Capital Expenditures. As soon as available, but in any event within 45 days after the end of each fiscal quarter of each fiscal year of the Company, commencing with the fiscal quarter ending March 31, 2009, a report detailing Capital Expenditures (i) actually made during such fiscal year of the Company compared to the budgeted amount therefor and (ii) projected for the remainder of such fiscal year;

(xiv) Annual Budget. As soon as available, but in any event within 60 days after the end of each fiscal year of the Company, an annual business plan and budget of the Company and its Subsidiaries on a Consolidated basis, prepared on a basis consistent with past practices, including forecasts prepared by management of the Company, in form reasonably satisfactory to the Required Holder(s); and

(xv) Other Information. Promptly upon request, such additional information regarding the financial position, assets or business (including with respect to environmental matters) of the Company or any Subsidiary as any Holder may reasonably request from time to time.

Together with any financial statements delivered under clauses (i) or (ii) hereof, the Company shall deliver a schedule showing the interest accrued on the Notes during such fiscal quarter and showing the computations in reasonable detail."

(l) **Paragraph 5R. Newly Acquired Real Property.** Paragraph 5R of the Agreement is hereby amended and restated in its entirety as follows:

"**Paragraph 5R. Newly Acquired Real Property.** Within 90 days (or such longer period as permitted by the Collateral Agent in its sole discretion) after each Newly Acquired Real Property Report is due, but in any event within 180 days after each Newly Acquired Real Property Report is due, the Collateral Agent and the Holders shall have received deeds of trust, trust deeds, deeds to secure debt, mortgages, leasehold mortgages and leasehold deeds of trust, in form reasonably satisfactory to the Collateral Agent and its counsel and counsel for the Required Holder(s), covering all real property interests owned by the Company and each Guarantor as reflected on the Newly Acquired Real Property Report (other than any such real property that the Collateral Agent and the Required Holder(s) each determines a perfected Lien is unnecessary due to the cost in relation to the benefit; provided, however, that such determination by the Required Holder(s) shall not be required so long as the aggregate amount of the cost of all real property with respect to which the Collateral Agent has determined under this paragraph 5R a lien is unnecessary does not exceed $5,000,000), duly executed by the Company or such Subsidiary."

(m) **Paragraph 5S. Leverage Fee.** A new paragraph 5S is hereby added to the end of paragraph 5 to read as follows:

"**Paragraph 5S. Leverage Fee.** The Company shall either make (a)(i) prepayments of principal under the Bank Agreement resulting in corresponding lending commitment reductions under the Bank Agreement in accordance with Section 2.04(b)(vi) of the Bank Agreement (other than as a result of Section 2.04(b)(viii) of the

Bank Agreement) and (ii) corresponding payments of principal of the Notes (other than PIK Notes) in accordance with paragraph 4A(ii) and/or (b)(i) prepayments of principal under the Bank Agreement resulting in corresponding lending commitment reductions under the Bank Agreement in accordance with Section 2.03(a) of the Bank Agreement and (ii) prepayments of principal of the Notes (other than PIK Notes) in accordance with paragraph 4B, but only if any lending commitment reductions under the Bank Agreement occur simultaneously with a pro rata (in accordance with the relative outstanding principal amount of the Bank Obligations and the Notes (other than PIK Notes)) prepayment of the Notes (other than PIK Notes) under paragraph 4B, in at least the cumulative amounts and on or before the dates set forth on the Leverage Fee Grid or the Company will pay to each Holder a leverage fee equal to the product of aggregate outstanding principal amount of the Notes (other than PIK Notes) held by such Holder in effect on the date set forth on the Leverage Fee Grid and the applicable percentage set forth on the Leverage Fee Grid (collectively, the **"Leverage Fee"**). Notwithstanding anything to the contrary contained herein, payments made and corresponding commitment reductions related thereto under Sections 2.03(c) and 2.04(b)(viii) of the Bank Agreement or the required prepayments of the Notes under paragraphs 4A(i) and 4F shall not be included to determine Company's compliance with this paragraph 5S. Such Leverage Fee shall be fully earned on the date indicated but shall be due and payable on the Refinancing Date. The receipt by the Holders of any Leverage Fee shall not constitute a waiver of any Default or Event of Default.

To the extent that a consent from the Required Holder(s) is necessary in order to permit a certain Asset Disposition for which the Net Cash Proceeds are to be included in the calculation of cumulative prepayments required hereunder, the Holders shall not charge a fee; provided, however, such agreement not to charge a consent fee shall be limited to a consent for which the sole purpose is to permit such Asset Disposition notwithstanding the $10,000,000 limitation in paragraph 6C(5)(vii)."

(n) **Paragraph 5T. Recalculation of Leverage Ratio.** A new paragraph 5T is hereby added to the end of paragraph 5 to read as follows:

"**Paragraph 5T. Recalculation of Leverage Ratio.** If, as a result of any restatement of or other adjustment to the financial statements of the Company, the Company or the Required Holder(s) determine in good faith that (i) the Leverage Ratio as calculated by the Company as of any applicable date was inaccurate and (ii) a proper calculation of the Leverage Ratio would have resulted in greater Additional Interest for such period, the Company shall immediately and retroactively be obligated to pay to the Holders, promptly on demand by the Required Holder(s) (or, after the occurrence of an actual or deemed entry of an order for relief with respect to the Company under the Bankruptcy Code of the United States, automatically and without further action by any Holder), an amount equal to the excess of the amount of Additional Interest that should have been paid for such period that is greater than the amount of Additional Interest actually paid by the Company for such period. This paragraph shall not limit the rights of any Holder under any other provision of this Agreement. The Company's obligations under this paragraph shall survive the repayment of all Obligations hereunder."

(o) **Paragraph 5U. Quarterly Update Calls.** A new paragraph 5U is hereby added to the end of paragraph 5 to read as follows:

"**Paragraph 5U. Quarterly Update Calls.** The Company shall have a periodic update call with the Holders within 45 days after the last Business Day of each fiscal quarter of the Company (or at another time reasonably requested by the Required Holder(s)) to discuss matters reasonably requested by the Required Holder(s) including but not limited to progress updates on the Company's strategic alternatives."

(p) **Paragraph 5V. Cash Management Accounts.** A new paragraph 5V is hereby added to the end of paragraph 5 to read as follows:

"**Paragraph 5V. Cash Management Accounts.** The Company shall and cause its Subsidiaries to maintain its deposit accounts, disbursement accounts and other cash management accounts (collectively, the "**Cash Management Accounts**") with a Bank or an Affiliate of a Bank which is a party to the Intercreditor Agreement,provided, however, to the extent that a Cash Management Account is with a Bank or an Affiliate of a Bank that ceases to be a party to the Bank Agreement Documents, the Company shall cause such account to be transferred to another Bank or closed within 30 days."

(q) **Paragraph 5W. Post-Closing Covenants.** A new paragraph 5W is hereby added to the end of paragraph 5 to read as follows:

"**Paragraph 5W. Post-Closing Covenants.**

(a) Within 90 days (or such longer period as permitted by the Collateral Agent in its sole discretion) after the Amendment No. 4 Effective Date, but in any event within 180 days after the Amendment No. 4 Effective Date, the Company shall deliver to the Collateral Agent and the Holders the following:

(i) deeds of trust, trust deeds, deeds to secure debt, mortgages, leasehold mortgages and leasehold deeds of trust, in form reasonably satisfactory to the Collateral Agent and its counsel and counsel for the Required Holder(s), and covering all unencumbered property interests held by the Company and each Guarantor as reflected on the Perfection Certificate (other than any such real property that the Collateral Agent and the Required Holder(s) each determines a perfected Lien is unnecessary due to the cost in relation to the benefit; provided, however, that such determination by the Required Holder(s) shall not be required so long as the aggregate amount of the cost of all real property with respect to which the Collateral Agent has determined under this paragraph 5W(i) a lien is unnecessary does not exceed $10,000,000), duly executed by the Company or such Guarantor;

(ii) account control agreements in form reasonably satisfactory to the Collateral Agent and counsel to the Required Holder(s) and duly executed by the appropriate parties with respect to each deposit account and each securities account of the Company and each Subsidiary that is not already the subject to an account control agreement in favor of the Collateral Agent; and

(iii) evidence that all insurance required to be maintained pursuant to the Loan Documents has been obtained and is in effect, together with the certificates of insurance, naming the Collateral Agent, on behalf of the Holders, the Banks and the Administrative Agent under the Bank Agreement, as an additional insured or loss payee, as the case may be, under all insurance policies maintained with respect to the assets and properties of the Company and its Subsidiaries that constitute Collateral.

(b) Within 5 Business Days after the Amendment No. 4 Effective Date, the Company shall deliver to each Holder duly executed (i) amended and restated Notes to reflect the amendments thereto made in Amendment No. 4 and (ii) Related PIK Notes.

(c) Within 45 days after the Amendment No. 4 Effective Date, the Company shall deliver to the Collateral Agent and the Holders, a complete and duly executed updated Perfection Certificate in form and substance reasonably satisfactory to counsel to the Holders."

(r) **Paragraph 6A(1). Capital Expenditures.** Paragraph 6A(1) of the Agreement is hereby amended and restated in its entirety as follows:

"**Paragraph 6A(1). Capital Expenditures.** The Company will not, or permit any Subsidiary to, make or become legally obligated to make any Capital Expenditure, except for Capital Expenditures in the ordinary course of business not exceeding, in the aggregate for the Company and its Subsidiaries during each fiscal year set forth below, the amount set forth opposite such fiscal year;

| Fiscal Year | Amount |
|---|---|
| 2009 | $120,000,000 |
| 2010 and any fiscal year thereafter | $ 75,000,000 |

provided, however; that (i) any amounts of permitted Capital Expenditures not made during any fiscal year may be carried forward and expended during the subsequent fiscal year, (ii) Capital Expenditures in the amount of $18,400,000 that, in accordance with GAAP, have been accrued by the Company on its financial statements for the fiscal year ended December 31, 2008 but made in 2009 shall be excluded when calculating the Capital Expenditures made in 2009, and (iii) the limitation on Capital Expenditures set forth above for fiscal year 2010 and thereafter shall not apply after the Leverage Ratio as of the end of each fiscal quarter for four consecutive fiscal quarters for the Company and its Subsidiaries on a Consolidated basis is less than 4.25 to 1.00. Notwithstanding anything to the contrary contained herein, Capital Expenditures made with Excess Proceeds shall be excluded from the calculation of aggregate Capital Expenditures permitted hereunder for any fiscal year."

(s) **Paragraph 6A(2). Interest Charge Coverage Ratio.** Paragraph 6A(2) of the Agreement is hereby amended and restated in its entirety as follows:

"6A(2). **Interest Charge Coverage Ratio.** The Company shall not, as of the end of any fiscal quarter, permit the Interest Charge Coverage Ratio for the Company and its Subsidiaries on a Consolidated basis to be less than the applicable ratio set forth below:

| Fiscal quarter ending: | Minimum Interest Charge Coverage Ratio |
|---|---|
| March 31, 2009 | 1.75:1.00 |
| June 30, 2009 | 1.50:1.00 |
| September 30, 2009 | 1.30:1.00 |
| December 31, 2009 | 1.15:1.00 |
| March 31, 2010 | 1.25:1.00 |
| June 30, 2010 | 1.50:1.00 |
| September 30, 2010 and December 31, 2010 | 1.75:1.00 |
| March 31, 2011 and each fiscal quarter thereafter | 2.50:1.00" |

(t) **Paragraph 6A(3). Leverage Ratio.** Paragraph 6A(3) of the Agreement is hereby amended and restated in its entirety as follows:

"6A(3). **Leverage Ratio.** The Company shall not, as of the end of any fiscal quarter, permit the Leverage Ratio for the Company and its Subsidiaries on a Consolidated basis to be greater than the applicable ratio set forth below:

| Fiscal quarter ending: | Maximum Leverage Ratio |
|---|---|
| March 31, 2009 | 7.25:1.00 |
| June 30, 2009 and September 30, 2009 | 8.25:1.00 |
| December 31, 2009 | 8.50:1.00 |
| March 31, 2010 | 8.00:1.00 |
| June 30, 2010 | 6.65:1.00 |
| September 30, 2010 | 5.25:1.00 |
| December 31, 2010 | 5.00:1.00 |
| March 31, 2011, June 30, 2011, September 30, 2011, December 31, 2011 and March 31, 2012 | 4.50:1.00 |
| June 30, 2012 and each fiscal quarter thereafter | 4.25:1.00" |

(u) **Paragraph 6B. Distribution, Etc.** Clauses (ii) and (iii) of paragraph 6B of the Agreement are hereby amended and restated in their entirety as follows:

"(ii) provided that no PIK Notes are outstanding and no Default or Event of Default exists before or immediately after such distribution (a) so long as the Leverage Ratio as of the fiscal quarter as to which such Minimum Quarterly Distribution relates is less than 4.25:1.00 but greater than or equal to 4.00:1.00 (after giving pro forma effect to such Minimum Quarterly Distributions described hereunder as though paid in such fiscal

quarter), the Company may declare and pay Minimum Quarterly Distributions and (b) so long as the Leverage Ratio as of the fiscal quarter as to which such Quarterly Distribution relates is less than 4.00:1.00 (after giving pro forma effect to such Quarterly Distributions described hereunder as though paid in such fiscal quarter), the Company may declare and pay Quarterly Distributions;

(iii) the Company may pay Minimum Quarterly Distributions and Quarterly Distributions within 60 days after the date of declaration thereof if, at the date of declaration, such payment would comply with clause (ii) of this paragraph 6B;"

(v) **Paragraph 6C(1). Liens, Etc.** Paragraph 6C(1) of the Agreement is hereby amended by (i) amending and restating clause (i) in its entirety, (ii) amending and restating clause (iii) in its entirety, (iii) deleting the "and" at the end of clause (xi), (iv) deleting the "." at the end of clause (xii) and inserting therefor "; and" and (v) adding a new clause (xiii) at the end thereof as follows:

"(i) Liens created by the Security Documents (provided, that the obligations of the Company to the Banks and Affiliates of the Banks in respect of Interest Rate Contracts and Hydrocarbon Hedge Agreements may be secured by such Liens only so long as, with respect to each Bank or Affiliate thereof, the Bank remains a Bank under the Bank Agreement and such Bank or such Affiliate is a party to the Intercreditor Agreement);

* * *

(iii) Liens securing obligations of such Person as lessee under Capital Leases permitted by paragraph 6C(2)(viii);

* * *

(xiii) Liens on any Hydrocarbon Cash Collateral provided for the benefit of the New York Mercantile Exchange that do not exceed $50,000,000 in the aggregate at any time outstanding."

(w) **Paragraph 6C(2). Debt.** Paragraph 6C(2) of the Agreement is hereby amended by (i) deleting the last paragraph of paragraph 6C(2) and (ii) amending and restating clauses (vii), (viii) and (x) in their entirety as follows:

"(vii) [Intentionally Deleted];

(viii) Debt in respect of Capital Leases and Debt secured by Liens permitted by paragraph 6C(1)(iv), not exceeding $70,000,000 in aggregate principal amount at any time outstanding;

* * *

(x) unsecured Debt in addition to Debt otherwise permitted herein not exceeding $30,000,000 in aggregate principal amount at any time outstanding; provided,

that, on and after the Amendment No. 4 Effective Date, no Debt shall be permitted under this clause (x) other than Debt issued or incurred by the Company or any Subsidiary that is a Guarantor;"

(x) **Paragraph 6C(4). Mergers, Acquisitions, Etc.** Paragraph 6C(4) of the Agreement is hereby amended by (i) amending and restating clause (i) in its entirety, (ii) deleting the "and" at the end of clause (iv), (iii) deleting the "." at the end of clause (v) and inserting therefor "; and" and (iv) adding a new clause (vi) at the end thereof as follows:

"(i) so long as no Default or Event of Default exists before or immediately after such event, the Company or any Subsidiary may make any Acquisition; provided, however, that any such Acquisition shall be permitted only if, (a) before the effectiveness of such Acquisition and to the extent required by the Required Holders, the Company delivers to the Holders (I) guaranties, mortgages, deeds of trust, security agreements, releases, UCC financing statements and UCC terminations, duly executed by the parties thereto, in form and substance satisfactory to the Required Holders and accompanied by UCC searches, title investigations and legal opinions (except with respect to priority) demonstrating that, upon the effectiveness of such Acquisition and the recording and filing of any necessary documentation, the Collateral Agent will have an Acceptable Security Interest on the Property to be acquired, (II) such other legal opinions in relation to the documents described in the foregoing subclause (I) as the Required Holders may reasonably request, and (III) evidence of company authority to enter into, and environmental assessments with respect to, such Acquisition, (b) the Company or such Guarantor is the acquiring or surviving entity, (c) the Acquisition would not reasonably be expected to cause a Default or Event of Default, (d) after giving effect to such Acquisition on a pro forma basis, the Company would have been in compliance with all of the covenants contained in this Agreement, including, without limitation, paragraph 6A as of the end of the most recent fiscal quarter, (e) the acquisition target is in the same or similar line of business as the Company and its Subsidiaries, (f) the terms of paragraph 6G are satisfied, and (g) if such Acquisition occurs before the Bank Agreement Refinancing Date or if the Leverage Ratio as of the fiscal quarter most recently ended prior to such Acquisition (after giving effect to such Acquisition on a pro forma basis) is greater than or equal to 4.25:1.00, such Acquisition is funded solely by use of Excess Proceeds;

* * *

(vi) so long as no Default or Event of Default exists before or immediately after such event, the Company may merge with or consolidate with any other Person, provided, however, that such merger or consolidation shall be permitted only if, (a) the Company is the surviving entity of such merger or consolidation, (b) no Change of Control results therefrom, (c) immediately after giving effect to such merger or consolidation, the Leverage Ratio and the Interest Charge Coverage Ratio shall not be negatively impacted, (d) the Collateral Agent will have an Acceptable Security Interest in all of the Collateral and each Guarantor will remain a Guarantor of the Obligations (unless such Guarantor is dissolved or merged into another Guarantor in connection with such transaction as otherwise permitted by this paragraph 6C(4)) and (e) the result of

such merger taken as a whole will not be materially adverse to the interests of the Holders; provided, however, if as a result of such transaction the Company's entity type (e.g., corporation, partnership, limited liability company or other) or tax nature changes (i) the Company shall deliver to the Holders such opinions of counsel and corporation, limited liability company or partnership documents in connection therewith as the Required Holder(s) may reasonably request and (ii) the Company and the Holders agree that this Agreement will be amended in a manner reasonably satisfactory to the Required Holder(s) (x) to make appropriate changes to reflect any changes to the entity type and/or tax nature of the Company while preserving the substance and terms of this Agreement and (y) without the payment of a consent fee or other fee with respect solely to the amendments to this Agreement specified in clause (x)."

(y) **Paragraph 6C(5)(vii). Sales, Etc. of Property.** Paragraph 6C(5)(vii) of the Agreement is hereby amended and restated in its entirety as follows:

"(vii) so long as no Default or Event of Default has occurred and is continuing or exists before or immediately after such event, (a) sales or transfers of new equipment by the Company or any Subsidiary in the ordinary course of business consistent with historical practice to any Person whereby the Company or any Subsidiary shall then or thereafter rent or lease as lessee such new equipment or any part thereof to use for substantially the same purpose or purposes as the new equipment sold or transferred, (b) relatively contemporaneous like-kind exchanges in the ordinary course of business and consistent with historical practice of the Company's or its Subsidiaries' assets for consideration not exceeding $10,000,000 in the aggregate in any fiscal year of the Company and (c) other sales, leases, transfers and dispositions of Property for consideration not exceeding $10,000,000 in the aggregate in any fiscal year of the Company (such amount not to include the proceeds of the Arkoma Sale); provided, that, the Net Cash Proceeds of such dispositions permitted by clauses (a) and (c) are used to prepay Notes to the extent required under paragraph 4A(ii)(a)."

(z) **Paragraph 6J. Bank Agreement.** Paragraph 6J is hereby amended and restated in its entirety to read as follows:

"**Paragraph 6J. Bank Agreement.** The Company will not amend, supplement or otherwise modify any term of the Bank Agreement without the prior written consent of the Required Holder(s), which consent will not be unreasonably withheld, which amendment, supplement or modification would have the effect of (i) increasing the aggregate commitments under the Bank Agreement above $1,300,000,000, (ii) increasing the rate of interest except with respect to imposing the default rate as provided for in the Bank Agreement on the date hereof or any fees charged on the Bank Obligations, (iii) adding any affirmative covenant, negative covenant or event of default, (iv) changing any affirmative covenant, negative covenant or event of default, or any definition used therein, if such change is adverse to the Company or (v) making any other change materially adverse to the interests of the Holders."

(aa) **Paragraph 6N. Equity Issuance Proceeds.** Paragraph 6 of the Agreement is hereby amended to add a new paragraph 6N as follows:

"**6N. Equity Issuance Proceeds.** The Company shall not receive any proceeds from any Equity Issuance, unless it shall have provided to the Holders a certificate signed by a Responsible Officer of the Company certifying that all of the conditions to borrowing under the Bank Agreement have been fulfilled or will be fulfilled after any payment of any such proceeds to the Banks under the Bank Agreement and that the Company will be able to borrow under the Bank Agreement the funds necessary to enable the Company to make the prepayments on the Notes required pursuant to paragraph 4A(ii)(d) as a result of such Equity Issuance."

(bb) **Paragraph 6O. Hydrocarbon Hedge Agreements and Interest Rate Contracts.**A new paragraph 6O is added to the end of paragraph 6 to read as follows:

"**Paragraph 6O. Hydrocarbon Hedge Agreements and Interest Rate Contracts.**The Company shall not and shall not permit any Subsidiary to be a party to or in any manner liable on any Hydrocarbon Hedge Agreement or Interest Rate Contract except:

(i) Hydrocarbon Hedge Agreements with the purpose and effect of hedging prices on Hydrocarbons that are (i) consistent in all material respects with the Company's risk management policies and historical practices and (ii) not speculative in nature;

(ii) Interest Rate Contracts with the purpose and effect of fixing interest rates on a principal amount of indebtedness of the Company that is accruing interest at a variable rate that are (a) consistent with the Company's risk management policies and historical practices and (b) not speculative in nature; and

(iii) Except for the Collateral under the Security Documents with respect to the Bank Obligations and the Obligations, no Hydrocarbon Hedge Agreement or Interest Rate Contract maintained with any Bank or any Affiliate of a Bank may require the Company or any Subsidiary to put up money, assets or other security against the event of its nonperformance prior to actual default by the Company or any Subsidiary in performing its obligations. No documents evidencing a Hydrocarbon Hedge Agreement or Interest Rate Contract maintained with any Bank or any Affiliate of any Bank shall be amended or modified in any way to advantage a counterparty thereto without amending or modifying all Hydrocarbon Hedge Agreements or Interest Rate Contracts (as applicable) maintained with any Bank or any Affiliate of a Bank to equally advantage such other counterparties."

(cc) **Paragraph 7A(ii). Acceleration.** Paragraph 7A(ii) of the Agreement is hereby amended and restated in its entirety as follows:

"(ii) the Company defaults in the payment of any Leverage Fee or interest on any Note for more than three Business Days after the date due; or"

(dd) **Paragraph 7A(xiv) and (xv). Acceleration.** Paragraphs 7A(xiv) and (xv) of the Agreement are hereby amended by deleting the reference to "paragraphs 6C(5) and 11T" where it appears therein and inserting therefor "paragraph 6C(5)".

(ee) **Paragraph 10A. Yield-Maintenance Terms.** Paragraph 10A of the Agreement is hereby amended by amending and restating the following terms as follows:

"**Called Principal**" means, with respect to any Note, the principal of such Note that is to be prepaid pursuant to paragraph 4A(ii) or 4B or is declared to be immediately due and payable pursuant to paragraph 7A, as the context requires.

"**Designated Spread**" means 1.00% in the case of each Series A Note and Series B Note, 0.50% in the case of each Series C Note, Series D Note, Series E Note and Series F Note, and 0% in the case of each Note of any other Series unless the Supplement with respect to the Notes of such Series specifies a different Designated Spread, in which case Designated Spread shall mean, with respect to each Note of such Series, the Designated Spread so specified; provided, that, for purposes of determining the Yield-Maintenance Amount of any Note upon acceleration thereof as a result of a failure by the Company to make any prepayment of the Notes required by paragraph 4A(ii)(d), then the Designated Spread provided herein for each Series of Notes shall be equal to 0.50%.

"**Settlement Date**" means, with respect to the Called Principal of any Note, the date on which such Called Principal is to be prepaid pursuant to paragraph 4A(ii) or 4B or is declared to be immediately due and payable pursuant to paragraph 7A, as the context requires.

(ff) **Paragraph 10A. Yield-Maintenance Terms.** Paragraph 10A of the Agreement is hereby further amended by amending the definition of "Yield-Maintenance Amount" to add a new sentence at the end thereof to read as follows:

"Notwithstanding any provisions in clauses (a) through (f) above, upon acceleration of any Note as a result of a failure by the Company to make any prepayment of the Notes required by paragraph 4A(ii)(d), the Yield-Maintenance Amount for each Note shall be an amount equal to the excess, if any, of the Discounted Value of the Called Principal of such Note over the sum of (i) such Called Principal plus (ii) interest accrued thereon as of (including interest due on) the Settlement Date with respect to such Called Principal, no matter what the Settlement Date is with respect to such acceleration, if greater than the amount that is otherwise determined pursuant the applicable clause (a) through (f) for such Note."

(gg) **Paragraph 10B. Other Terms.** Paragraph 10B of the Agreement is hereby amended by amending and restating or adding the following new terms in their appropriate alphabetical order as follows:

**"Additional Interest"** shall have the meaning specified in paragraph 1I.

**"Amendment No. 4"** means Letter Amendment No. 4, dated as of February 27, 2009, among the Company and the Holders.

**"Amendment No. 4 Effective Date"** shall have the meaning given in Amendment No. 4.

**"Applicable Percentage"** means, (a) with respect to the Net Cash Proceeds from any Asset Disposition, Recovery Event or issuance or incurrence of Debt, other than Debt permitted by paragraph 6C(2), 100% and (b) with respect to Net Cash Proceeds from the issuance or incurrence of any Debt permitted by paragraph 6C(2)(x) or 6C(2)(xi) or any Equity Issuance, the percentage set forth below for such proceeds:

| *Leverage Ratio (giving pro forma effect to such transaction and the use of proceeds thereof for the proportional level of Leverage Ratio) as of the fiscal quarter most recently ended* | *Percentage of Net Cash Proceeds from Debt that must be used for prepayment* | *Percentage of Net Cash Proceeds from Equity Issuances that must be used for prepayment* |
|---|---|---|
| ³ 4.50 | 100% | 50% |
| ³ 3.50 and < 4.50 | 50% | 25% |
| < 3.50 | 0% | 0% |

**"Arkoma Sale"** means the transactions contemplated by that certain Asset Purchase Agreement dated as of February 9, 2009, among Producers Gas Gathering, JV, Crosstex Arkoma, LLC, and Crosstex Energy Services, L.P.

**"Asset Disposition"** means any sale, transfer, license, lease or other disposition (including any sale and leaseback transaction) of any Property or any series of related dispositions of Property by the Company or any Subsidiary, including any sale, assignment, transfer or other disposal, with or without recourse, of any notes or accounts receivable or any rights and claims associated therewith in which the Property disposed either (a) generates EBITDA greater than or equal to 1% of EBITDA for the four fiscal quarter period ending as of the most recent fiscal quarter for which the Company has delivered financial statements pursuant to paragraph 5A(i) or (ii) or (b) has an aggregate book value greater than 1% of the book value of the consolidated assets of the Company and its Subsidiaries as of the end of the most recent fiscal quarter for which the Company has delivered financial statements pursuant to paragraph 5A(i) or (ii); provided, that the term "Asset Disposition" shall not include any transaction permitted by (x) paragraph 6C(5)(i), (y) the first $5,000,000 of Net Cash Proceeds received in any fiscal year of the Company or its Subsidiaries in the aggregate pursuant to paragraph 6C(5)(ii), and (z) paragraph 6C(5)(iii), (iv), (v), (vi) or (vii)(b); provided, that, no sale, transfer, license, lease or other disposition of Property shall be excluded as an "Asset Disposition" if resulting in a permanent reduction in the lending commitments under the Bank Agreement.

**"Bank Agreement Refinancing Date"** means the date of the refinancing (whether (i) by amendment and restatement of the Bank Agreement that extends the terms of the commitments to lend or provide other financial accommodations thereunder

to after June 29, 2011 or (ii) otherwise) of the Company's obligations under the Bank Agreement.

**"Bank Leverage Fee"** means a fee equal to the product of aggregate commitments in effect under the Bank Agreement on the date set forth on the Leverage Fee Grid and the applicable percentage set forth on the Leverage Fee Grid.

**"Capital Assets"** means, with respect to any Person, all equipment, fixed assets and real Property or improvements of such Person, or replacements or substitutions therefor or additions thereto, that, in accordance with GAAP, have been or should be reflected as additions to property, plant or equipment on the balance sheet of such Person.

**"Capital Expenditures"** means, with respect to any Person for any period, any expenditure in respect of the purchase or other acquisition of any Capital Asset (excluding normal replacements and maintenance which are properly charged to current operations). For purposes of this definition, the purchase price (or, if such Capital Asset has already been purchased, the fair market value) of any Capital Asset that is traded in, swapped or exchanged for any existing Capital Asset or with insurance proceeds shall be included in Capital Expenditures only to the extent of the gross amount by which such purchase price exceeds the credit granted by the seller of such Capital Asset for the Capital Asset being traded in at such time or the amount of such insurance proceeds, as the case may be.

**"Cash Interest Expense"** means, for the Company and its Subsidiaries determined on a Consolidated basis, for any period, Interest Expense for such period, less, to the extent included in the calculation of Interest Expense, the sum of (a) any Additional Interest paid during such period by adding the amount thereof to any PIK Note (to the extent attributable to interest for such period) and interest on the PIK Notes, (b) amortization of debt issuance costs, debt discount or premium and other financing fees and expenses incurred by the Company or any of its Subsidiaries, and (c) the incurrence of any obligation to pay the Leverage Fee and the Bank Leverage Fee.

**"Cash Management Accounts"** shall have the meaning specified in paragraph 5V.

**"Collateral"** means all Collateral as defined in each of the Security Agreements and each of the Mortgages and all property in which a security interest is granted to the Collateral Agent under any other Security Document.

**"Costs of Amendments"** means all upfront, consent, legal, professional and advisory fees paid by the Company (whether or not incurred by the Company) in connection with the negotiation and execution, delivery and performance of the Company's obligations under (a) each amendment to the Bank Agreement executed on or prior to the Amendment No. 4 Effective Date, among the Company, the Banks party thereto, and the Administrative Agent and (b) each amendment to this Agreement executed on or prior to the Amendment No. 4 Effective Date, among the Company, the Guarantors and the Holders party thereto.

**"Default Rate"** means, for any Note at any time upon the occurrence of an Event of Default and until such Event of Default has been cured or waived in writing, a rate of interest per annum from time to time equal to the lesser of (i) the maximum rate permitted by applicable law and (ii) the greater of (a) 2% over the coupon rate for such Note over the rate of interest in effect immediately prior to such Event of Default and (b) 2.0% over the rate of interest publicly announced by JPMorgan Chase Bank from time to time in New York City as its Prime Rate, plus, in either case, any Additional Interest.

**"EBITDA"** means, for the Company and its Subsidiaries on a Consolidated basis for any period, (a) Net Income for such period plus (b) to the extent deducted in determining Net Income, Interest Expense, taxes, depreciation, amortization and other noncash items for such period minus (c) to the extent included in determining Net Income, all noncash items increasing Net Income for such period plus (d) to the extent deducted in determining Net Income, Costs of Amendments. Notwithstanding the foregoing, the purchase price of commodity derivative instruments, net of all proceeds from the sale of such instruments, may be amortized over the remaining term of such instruments.

For purposes of calculating the Leverage Ratio and Interest Coverage Ratio, EBITDA shall be calculated, on a pro forma basis, after giving effect to, without duplication, any Acquisition permitted under the terms of this Agreement occurring during the period commencing on the first day of such period to and including the date of such Acquisition (the "**Reference Period**"), as if such Acquisition occurred on the first day of the Reference Period. In making the calculation contemplated by the preceding sentence, EBITDA generated or to be generated by such acquired Person or by such acquired Property shall be determined in good faith by the Company based on reasonable assumptions and may take into account pro forma expenses that would have been incurred by the Company and its Subsidiaries in the operation of such acquired Person or acquired Property, during such period computed on the basis of personnel expenses for employees retained or to be retained by the Company and its Subsidiaries in the operation of such acquired Person or acquired Property and non-personnel costs and expenses incurred by the Company and its Subsidiaries in the operation of the Company's and its Subsidiaries' business at similarly situated facilities of the Company or any of its Subsidiaries; provided, however, that such pro forma calculations shall be reasonably acceptable to the Required Holder(s) if the Company does not provide the Holder with an Approved Consultant's Report supporting such pro forma calculations.

For purposes of calculating the Leverage Ratio and the Interest Coverage Ratio, EBITDA shall be calculated by deducting, to the extent previously included in the calculation for any relevant period, EBITDA attributable to a particular asset subject to an Asset Disposition prepayment required by paragraph 4A(ii)(a) after giving effect to such Asset Disposition occurring during the period commencing on the first day of such period to and including the date of such Asset Disposition (the "**Asset Disposition Reference Period**"), as if such Asset Disposition occurred on the first day of the Asset Disposition Reference Period.

Notwithstanding any provision of this Agreement which may otherwise be to the contrary, if any lease pursuant to the Eunice Lease Documents is treated under GAAP as a Capital Lease, then, for all computations of EBITDA hereunder, such lease shall be treated as an operating lease and Net Income, Interest Expense, taxes, depreciation, amortization and other noncash items, for all purposes of determining EBITDA under this Agreement for any period, shall be adjusted as though such lease was accounted for as an operating lease.

**"ECF Capital Expenditures"** means, for any period, without duplication, the sum of all expenditures made by the Company and its Subsidiaries during such period for Capital Assets, but excluding (a) any such expenditures financed with Excess Proceeds, and (b) expenditures made with amounts paid to the Company and its Subsidiaries by third parties aiding in construction for such Capital Assets. For the sake of clarity amounts paid to the Company and its Subsidiaries by third parties aiding in construction for Capital Assets that have not been expended in construction for such Capital Assets shall not be included in the calculation of ECF Capital Expenditures.

**"Excess Cash Flow"** means, for any fiscal year of the Company, the excess (if any) of (a) EBITDA for such fiscal year (without giving effect to any pro forma adjustments made to EBITDA as a result of Acquisitions or Asset Dispositions) over (b) the sum (for such fiscal year), without duplication, of (i) Cash Interest Expense, (ii) scheduled principal repayments on the Obligations and scheduled principal repayments and amortization of Debt permitted by paragraph 6C(2)(viii), to the extent actually made, (iii) all taxes actually paid in cash by the Company and its Subsidiaries during such fiscal year (excluding items included in this calculation during the prior year as a reserve) or that will be paid within six months after the end of such fiscal year and for which reserves have been established, (iv) all prepayments of Debt made by the Company pursuant to Section 2.03 of the Bank Agreement in amounts equal to the corresponding lending commitment reductions under the Bank Agreement in connection with such prepayments, (v) ECF Capital Expenditures actually made by the Company and its Subsidiaries as permitted hereunder, but excluding any such ECF Capital Expenditures made in such fiscal year where a certificate in the form contemplated by the following clause (vi) was previously delivered and (vi) ECF Capital Expenditures that the Company or any of its Subsidiaries shall, during such fiscal year, become obligated to make but that are not made during such fiscal year, provided that the Company shall deliver a certificate to the Holders not later than 90 days after the end of such fiscal year, signed by a Responsible Officer and certifying that such ECF Capital Expenditures were made during such 90-day period and were not financed with Excess Proceeds.

**"Excess Cash Flow Prepayment Amount"** means an amount equal to 75% of Excess Cash Flow from each of the Company's fiscal years ending December 31, 2009 and December 31, 2010; provided, that, if the Leverage Ratio for the fourth quarter of such fiscal year is less than 4.50:1.00, then, the "Excess Cash Flow Prepayment Amount" for such fiscal year shall be an amount equal to 50% of Excess Cash Flow from such fiscal year.

**"Excess Cash Flow Prepayment Date"** means the date that is 90 days after the end of each of the Company's fiscal years ending December 31, 2009 and December 31, 2010.

**"Excess Proceeds"** means the Net Cash Proceeds from any issuance or incurrence of any Debt or Equity Issuance not required to be used to prepay the Bank Obligations pursuant to Section 2.04(b)(iii) and 2.04(b)(iv) of the Bank Agreement or the Obligations pursuant to paragraph 4A(ii)(c) and 4A(ii)(d).

**"Hydrocarbon Cash Collateral"** means the amount of cash and Permitted Investments pledged and deposited with or delivered to a Person by the Company or any Subsidiary as collateral for obligations of the Company or any Subsidiary under any Hydrocarbon Hedge Agreements.

**"Interest Charge Coverage Ratio"** means, for the Company and its Subsidiaries on a Consolidated basis, as of the end of any fiscal quarter, the ratio of (a) EBITDA for the four-fiscal quarter period then ended to (b) Cash Interest Expenses for the four-fiscal quarter period then ended.

**"Interest Expense"** means, for the Company and its Subsidiaries determined on a Consolidated basis, for any period, the total interest, letter of credit fees, and other fees incurred in connection with any Debt for such period (excluding all Costs of Amendments), whether paid or accrued, including, without limitation, all commissions, discounts and other fees and charges owed with respect to letters of credit and bankers' acceptance financing, all as determined in conformity with GAAP. For purposes of calculating the Interest Charge Coverage Ratio, Interest Expense shall be calculated by deducting, to the extent previously included in the calculation for any relevant period, the amount of interest incurred by the Company in connection with (a) advances under the Bank Agreement that have been prepaid pursuant to Section 2.04(b)(ii) of the Bank Agreement and (b) the principal amount of Notes that have been prepaid pursuant to paragraph 4A(ii)(a), in both instances, during the period commencing on the first day of such period to and including the date of such prepayment.

**"Leverage Fee"** shall have the meaning specified in paragraph 5S.

**"Leverage Ratio"** means, for the Company and its Subsidiaries on a Consolidated basis, as of the end of any fiscal quarter, the ratio of (a) Funded Debt for the Company and its Subsidiaries on a Consolidated basis as of the end of such fiscal quarter to (b) EBITDA for the four fiscal quarters then ended, provided, however, the outstanding principal amount of the PIK Notes and the incurrence of any obligation to pay the Leverage Fee and the Bank Leverage Fee shall not be included in the definition of Funded Debt for the calculation of the Leverage Ratio.

**"Leverage Fee Grid"** means the grid set forth below, which is used to determine the Leverage Fee payable by the Company pursuant to paragraph 5S:

| Period Ending | Cumulative Prepayments Under this Agreement and Bank Agreement | Leverage Fee Payable Under this Agreement (based on the aggregate outstanding principal amount of the Notes (other than PIK Notes)) and the Bank Agreement |
|---|---|---|
| September 30, 2009 | $ 100,000,000 | 1.00% |
| December 31, 2009 | $ 200,000,000 | 1.00% |
| March 31, 2010 | $ 300,000,000 | 2.00% |

**"Material Subsidiary"** means a Subsidiary of the Company having: either (a) 1% or more of EBITDA for the four fiscal quarter period ending as of the most recent fiscal quarter for which the Company has delivered financial statements pursuant to paragraph 5A(i) or (ii); or (b) 1% of the book value of the Consolidated assets of the Company and its Subsidiaries as of the end of the most recent fiscal quarter for which the Company has delivered financial statements pursuant to paragraph 5A(i) or (ii); provided, however, to the extent that executing a Guaranty would result in adverse tax consequences with respect to any non-operating Subsidiary listed on Schedule 10B(4) hereto on the Amendment No. 4 Effective Date (as reasonably determined by the Company), such non-operating Subsidiary shall not be considered a "Material Subsidiary" unless such non-operating Subsidiary has (i) 5% or more of EBITDA for the four fiscal quarter period ending as of the most recent fiscal quarter for which the Company has delivered financial statements pursuant to paragraph 5A(i) or (ii) or (ii) 5% of the book value of the Consolidated assets of the Company and its Subsidiaries as of the end of the most recent fiscal quarter for which the Company has delivered financial statements pursuant to paragraph 5A(i) or (ii).

**"Minimum Quarterly Distributions"** shall have the meaning set forth in Section 1.1 of the Company Partnership Agreement.

**"Net Cash Proceeds"** means (a) in connection with any Asset Disposition or Recovery Event, the proceeds thereof in the form of cash and cash equivalents (including any such proceeds received by way of deferred payment of principal pursuant to a note or installment receivable or purchase price adjustment receivable or otherwise, but only as and when received) of such Asset Disposition or Recovery Event, net of attorneys' fees, accountants' fees, investment banking fees and insurance consultant fees, amounts required to be applied to the repayment of Debt secured by a Lien permitted hereunder on any asset which is the subject of such Asset Disposition or Recovery Event (other than any Lien pursuant to a Security Document) and other customary fees and expenses actually incurred in connection therewith and net of taxes paid or reasonably estimated to be payable as a result thereof within two years of the date of the relevant Asset Disposition or Recovery Event as a result of any gain recognized in connection therewith (after taking into account any applicable tax credits or deductions and any tax sharing arrangements) and (b) in connection with any issuance or sale of debt securities or instruments or the incurrence of loans or Equity Issuance, the cash proceeds or cash equivalents received from such issuance or incurrence or Equity Issuance, net of

attorneys' fees, investment banking fees, brokerage, finder's or similar fees, accountants' fees, underwriting discounts and commissions and other customary fees and expenses actually incurred in connection therewith.

**"Newly Acquired Real Property Report"** shall have the meaning specified in paragraph 5A(xii).

**"Obligations"** means all present and future indebtedness, liabilities and obligations of any kind and nature whatsoever of the Company or any Subsidiary, including, without limitation, default interest, interest accruing at the then applicable rate provided in this Agreement after the maturity of the Notes and interest accruing at the then applicable rate provided in this Agreement after the filing of any petition in bankruptcy, or the commencement of any insolvency, reorganization or like proceeding, relating to the Company or any Subsidiary, whether or not a claim for post-filing or post-petition interest is allowed in such proceeding), whether direct or indirect, absolute or contingent, due or to become due, or now existing or hereafter incurred, that arise under, out of, or in connection with, this Agreement or any other Loan Document, the Notes or any other document made, delivered or given in connection therewith, whether on account of principal, interest, Yield-Maintenance Amount, fees, indemnities, costs, expenses or otherwise (including, without limitation, all fees and disbursements of counsel to the Collateral Agent and the Holders that are required to be paid by the Company and the Guarantors pursuant to the terms of the Loan Documents or this Agreement).

**"Perfection Report"** shall have the meaning specified in Amendment No. 4.

**"PIK Note Maturity Date"** means the date that is 180 days after the Refinancing Date.

**"PIK Notes"** shall have the meaning specified in paragraph 1H(6).

**"Recovery Event"** means any settlement of or payment in respect of any property or casualty insurance claim (excluding any claim in respect of business interruption) or any condemnation proceeding relating to any asset of the Company or any of its Subsidiaries, in which the subject property either (a) generates EBITDA greater than or equal to 1% of EBITDA for the four fiscal quarter period ending as of the most recent fiscal quarter for which the Company has delivered financial statements pursuant to paragraph 5A(i) or (ii) or (b) has an aggregate book value greater than 1% of the book value of the Consolidated assets of the Company and its Subsidiaries as of the end of the most recent fiscal quarter for which the Company has delivered financial statements pursuant to paragraph 5A(i) or (ii); provided, that, no such settlement or payment shall be excluded as a "Recovery Event" if resulting in a permanent reduction in the lending commitments under the Bank Agreement.

**"Refinancing Date"** means the earlier of (i) June 29, 2011 and (ii) the Bank Agreement Refinancing Date.

**"Reinvestment Deferred Amount"** with respect to any Reinvestment Event, the aggregate Net Cash Proceeds received by the Company or any of its Subsidiaries in connection therewith that are not required to be applied to prepay the Notes pursuant to paragraph 4A(ii)(a) or the Bank Obligations as a result of the delivery of a Reinvestment Notice.

**"Reinvestment Event"** means any Recovery Event in respect of which a Reinvestment Notice has been delivered.

**"Reinvestment Notice"** means a written notice executed by a Responsible Officer stating that no Event of Default has occurred and is continuing and that the Company (directly or indirectly through a Subsidiary) intends and expects to use all or a specified portion of the Net Cash Proceeds of a Recovery Event to acquire assets useful in its business and/or to repair Property, as applicable.

**"Related PIK Notes"** means, with respect to any Notes of any Series, the PIK Note of the Series with the same alphabetical designation as such Note issued with respect to such Note on the Amendment No. 4 Effective Date.

**"Required Holder(s)"** means the Holder or Holders of at least 50.1% of the aggregate principal amount of the Notes outstanding at such time; provided, that, so long as there are at least two Holders each of which holds at least $15,000,000 principal amount of Series F Notes who were Holders of Series F Notes as of the Amendment No. 4 Effective Date, then any vote of Required Holder(s) must include at least two Holders each of which holds at least $15,000,000 of Series F Notes who were Holders of Series F Notes as of the Amendment No. 4 Effective Date. Each group of Holders who are Affiliated will be considered one Holder for this purpose.

**"Series A PIK Notes"** shall have the meaning specified in paragraph 1H(1).

**"Series B PIK Notes"** shall have the meaning specified in paragraph 1H(2).

**"Series C PIK Notes"** shall have the meaning specified in paragraph 1H(3).

**"Series D PIK Notes"** shall have the meaning specified in paragraph 1H(4).

**"Series E PIK Notes"** shall have the meaning specified in paragraph 1H(5).

**"Series F PIK Notes"** shall have the meaning specified in paragraph 1H(6).

(hh) **Paragraph 10B. Other Terms.** Paragraph 10B of the Agreement is hereby further amended by deleting the following terms therefrom:

**"Acquisition Adjustment Period"**

**"Collateral Release Date"**

**"Excess Leverage Fee"**

**"Proposed Prepayment Date"**

**"RBC Event"**

**"RBC Fee"**

**"Scheduled Completion Date"**

**"Senior Leverage Ratio"**

(ii) **Paragraph 11C. Consents to Amendments.** Paragraph 11C of the Agreement is hereby amended by deleting the word "decrease" before the words "the rate" in the first sentence of such paragraph.

(jj) **Paragraph 11T. Release of Collateral.** Paragraph 11T of the Agreement is hereby amended and restated in its entirety as follows:

"11T. [Intentionally Deleted]."

(kk) **Exhibits A-1 through A-5 to the Agreement.** Exhibits A-1, A-2, A-3, A-4 and A-5 shall be amended and restated in their entirety as Exhibits A-1-A, A-2-A, A-3-A, A-4-A and A-5-A attached hereto.

(ll) **New Exhibits to the Agreement.** The Agreement is hereby amended by adding the following new Exhibits A-1-B, A-2-B, A-3-B, A-4-B, A-5-B and A-6-B thereto to read as set forth in Exhibits A-1-B, A-2-B, A-3-B, A-4-B, A-5-B and A-6-B attached hereto.

(mm) **New Schedules to the Agreement.** The Agreement is hereby amended by adding the following new Schedules 5A and 10B(4) thereto to read as set forth in Schedules 5A and 10B(4) attached hereto.

**2. Representations and Warranties.** In order to induce the Holders to enter into this Amendment, the Company hereby represents and warrants as follows:

(a) The execution, delivery and performance by the Company and the Guarantors of this Amendment, the Agreement, as amended hereby, and each of the documents described in paragraph 3 hereof to which each is a party, have in each case been duly authorized by all necessary limited liability company, limited partnership or other organizational action and do not and will not (i) contravene the terms of the Company Partnership Agreement or the partnership or limited liability company agreement or certificate of formation (or other organizational documents) of the General Partner, the Company or any of their Subsidiaries, (ii) conflict with or result in any breach or contravention of, or the creation of any Lien under, any document evidencing any contractual obligation to which the General Partner, the Company or any of their Subsidiaries is a party and which could subject any holder of Notes to any liability, (iii) conflict with or result in any breach or contravention of any order, injunction, writ or decree of any governmental authority binding on the General Partner, the Company, any of their Subsidiaries or their respective properties, (iv) violate any applicable law binding on or affecting the General

Partner, the Company or any of their Subsidiaries, or (v) adversely affect the enforceability of any Lien of the Security Documents.

(b) Each of the representations and warranties contained in paragraph 8 of the Agreement is true and correct in all material respects on and as of the date hereof, and will be true and correct in all material respects immediately upon, and as of the date of, the effectiveness of this Amendment in each case except (i) to the extent that such representations and warranties specifically refer to an earlier date, in which case they shall be true and correct in all material respects as of such earlier date and (ii) with respect to the last sentence of paragraph 8B of the Agreement.

(c) On and as of the date hereof, and after giving effect to this Amendment, no Default or Event of Default exists under the Agreement.

(d) No Governmental Action or consent of any other Person under any agreement to which the Company or any of its Subsidiaries is a party (other than consents that have been obtained) is required for the due execution, delivery or performance by the Company or the Guarantors of this Amendment, the Agreement, as amended hereby, or each of the documents described in paragraph 3 hereof to be executed by the Company or any Guarantor.

(e) This Amendment, the Agreement, as amended hereby, and each of the documents described in paragraph 3 hereof to be executed by the Company or any Guarantor, constitute legal, valid and binding obligations of the Company or such Guarantor, as applicable, enforceable against the Company or such Guarantor, as applicable, in accordance with their respective terms, except as the enforceability thereof may be limited by bankruptcy, insolvency, moratorium, reorganization or other similar laws affecting creditors' rights generally or by general principles of equity (regardless of whether such enforceability is considered in any proceeding in law or in equity).

(f) The quarterly and annual financial statements most recently delivered to each Holder pursuant to paragraphs 5A(i) and 5A(ii) of the Agreement fairly present the Consolidated financial condition of the Company and its Subsidiaries as of the respective dates thereof and the Consolidated results of the operations of the Company and its Subsidiaries for the respective fiscal periods ended on such dates, all in accordance with GAAP applied on a consistent basis (subject to normal year-end audit adjustments and the absence of footnotes in the case of the quarterly financial statements). Since September 30, 2008, no Material Adverse Effect has occurred. The Company and its Subsidiaries have no material contingent liabilities except as disclosed in such financial statements or the notes thereto.

(g) There is no pending or, to the knowledge of the Company, threatened action or proceeding affecting the Company or any Subsidiary before any Governmental Person, referee or arbitrator that could reasonably be expected to have a Material Adverse Effect.

(h) Neither the Company, the General Partner, the Ultimate General Partner nor any of their Subsidiaries have paid, or agreed to pay, any fees or other compensation to the lenders under the Bank Agreement for or with respect to the Amendment to Bank Agreement (as defined below) except for the fees and other compensation payable as set forth in the Bank Agreement,

as amended by the Amendment to Bank Agreement, and an amendment fee of 0.50% of the amount of the Commitments (as defined in the Bank Agreement as in effect on the date hereof) of the lenders under the Bank Agreement executing the Amendment to Bank Agreement and the reimbursement of legal fees and expenses incurred in connection with the Amendment to Bank Agreement.

(i) As of the date hereof, the Company has no (a) Material Subsidiaries other than those listed on Schedule 2(a) attached hereto and (b) non-Material Subsidiaries other than those listed on Schedule 2(b) attached hereto.

**3. Conditions to Effectiveness.** When each of the following conditions have been satisfied the amendments to the Agreement in paragraph 1 shall become effective as of the date (the "**Amendment No. 4 Effective Date**") first above written:

(a) Each Holder shall have received the following, each to be dated the date of execution and delivery thereof unless otherwise indicated, and each to be in form and substance satisfactory to the Required Holder(s) and executed and delivered by each of the parties thereto:

(i) this Amendment, duly executed by the Company, the Guarantors and the Holders;

(ii) an executed copy of an amendment to the Bank Agreement providing for amendments to the Bank Agreement substantially the same as the amendments to the Agreement as set forth in this Amendment (the **"Amendment to Bank Agreement"**);

(iii) an executed copy of an amendment to the Intercreditor Agreement;

(iv) a completed and duly executed copy of a Perfection Certificate executed by the Company (the '**Perfection Certificate**");

(v) such certificates of resolutions or other action, incumbency certificates and/or other certificates of Responsible Officers of the Company and each Guarantor as the Required Holder(s) may reasonably require evidencing the identity, authority and capacity of each Responsible Officer thereof authorized to act as a Responsible Officer in connection with this Amendment and the other Loan Documents to which the Company and such Guarantor is a party or is to be a party;

(vi) such documents and certifications as the Required Holder(s) may reasonably require to evidence that the Company and each Guarantor is duly organized or formed, and that the Company and each Guarantor is validly existing, in good standing and qualified to engage in business; and

(vii) such other documents, instruments and certificates as reasonably requested by the Required Holder(s).

(b) each Holder shall have received a payment of an amendment fee in an amount equal to 0.50% times the aggregate principal amount of the Notes held by such Holder on the date of this Amendment, which receipt shall, for purposes of determining satisfaction of this

condition precedent (but not for the purpose of determining whether such amendment fee was actually received by such Holder), absent manifest error, be conclusively determined upon the Company providing the Holders' special counsel in connection with this Amendment with Federal reference numbers evidencing such payments (and the Company hereby agrees to pay each Holder such amendment fee on or before the Amendment No. 4 Effective Date).

(c) The Company shall have paid the expenses of the special counsel to the Holders referred to in paragraph 5(c).

(d) The representations and warranties set forth in paragraph 2 of this Amendment shall be true and correct on and as of the date hereof.

**4. Release.** As a material part of the consideration for the Holders entering into this Amendment, the Company and each Guarantor executing this Amendment (collectively "**Releasor**") agree as follows (the "**Release Provision**"):

(a) Releasor hereby releases and forever discharges each Holder and each Holder's predecessors, successors, assigns, officers, managers, directors, shareholders, employees, agents, attorneys, representatives, parent corporations, subsidiaries, and affiliates (hereinafter all of the above collectively referred to as "**Noteholder Group**") jointly and severally from any and all claims, counterclaims, demands, damages, suits, actions, and causes of action of any nature whatsoever occurring prior to the date hereof, including, without limitation, all claims, demands, and causes of action for contribution and indemnity, whether arising at law or in equity, presently possessed, whether known or unknown, whether liability be direct or indirect, liquidated or unliquidated, presently accrued, whether absolute or contingent, foreseen or unforeseen, and whether or not heretofore asserted ("**Claims**"), which Releasor may have or claim to have against any of Noteholder Group, in each case to the extent such Claims arose out of or relate to the Agreement or the transactions contemplated thereby; except, as to any member of the Noteholder Group, to the extent that any such Claims results from any of gross negligence or willful misconduct of that member.

(b) Releasor agrees not to sue any of Noteholder Group or in any way assist any other person or entity in suing Noteholder Group with respect to any claim released herein. The Release Provision may be pleaded as a full and complete defense to, and may be used as the basis for an injunction against, any action, suit, or other proceeding which may be instituted, prosecuted, or attempted in breach of the release contained herein.

(c) Releasor acknowledges, warrants, and represents to Noteholder Group that:

(i) Releasor has read and understands the effect of the Release Provision. Releasor has had the assistance of independent counsel of its own choice, or has had the opportunity to retain such independent counsel, in reviewing, discussing, and considering all the terms of the Release Provision; and if counsel was retained, counsel for Releasor has read and discussed the Release Provision with Releasor. Before execution of this Amendment, Releasor has had adequate opportunity to make whatever investigation or inquiry it may deem necessary or desirable in connection with the subject matter of the Release Provision.

(ii) Releasor is not acting in reliance on any representation, understanding, or agreement not expressly set forth herein. Releasor acknowledges that Noteholder Group has not made any representation with respect to the Release Provision except as expressly set forth herein.

(iii) Releasor has executed the Release Provision with the understanding that the Holders are relying on it in agreeing to enter into this Agreement and that the Holders would not execute this Amendment unless Releasor executed the Release Provision.

(iv) Releasor is the sole owner of the claims released by the Release Provision, and Releasor has not heretofore conveyed or assigned any interest in any such claims to any other person or entity (other than the conveyance pursuant to the Security Documents).

(d) Releasor understands that the Release Provision was a material consideration in the agreement of each Holder to enter into this Amendment.

(e) It is the express intent of Releasor that the release and discharge set forth in the Release Provision be construed strictly in accordance with its terms.

(f) If any term, provision, covenant, or condition of the Release Provision is held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the remainder of the provisions shall remain in full force and effect.

**5. Miscellaneous.**

(a) **Effect on Agreement**. On and after the Amendment No. 4 Effective Date, each reference in the Agreement to "this Agreement", "hereunder", "hereof", or words of like import referring to the Agreement and each reference in the Notes and all other documents executed in connection with the Agreement to "the Agreement", "thereunder", "thereof", or words of like import referring to the Agreement shall mean the Agreement as amended by this Amendment. The Agreement, as amended by this Amendment, is and shall continue to be in full force and effect and is hereby in all respects ratified and confirmed. The execution, delivery and effectiveness of this Amendment shall not operate as a waiver of any right, power or remedy under the Agreement nor constitute a waiver of any provision of the Agreement. Without limiting the generality of the foregoing, nothing in this Amendment shall be deemed to (i) constitute a waiver of compliance or consent to noncompliance by the Company or any other Person with respect to any term, provision, covenant or condition of the Agreement or any other Loan Document or (ii) prejudice any right or remedy that any holder of Notes may now have or may have in the future under or in connection with the Agreement or any other Loan Document.

(b) **Counterparts**. This Amendment may be executed in any number of counterparts (including those transmitted by facsimile) and by any combination of the parties hereto in separate counterparts, each of which counterparts shall be an original and all of which taken together shall constitute one and the same Amendment. Delivery of this Amendment may be made by facsimile transmission of a duly executed counterpart copy hereof.

(c) **Expenses**. The Company confirms its agreement, pursuant to paragraph 11B of

the Agreement, to pay promptly all out-of-pocket expenses of the Holders related to the preparation, negotiation, reproduction, execution and delivery of this Amendment and all matters contemplated hereby and thereby, including without limitation all fees and out-of-pocket expenses of the Holders' special counsel.

(d) **Governing Law. THIS AMENDMENT SHALL BE CONSTRUED AND ENFORCED IN ACCORDANCE WITH, AND THE RIGHTS OF THE PARTIES SHALL BE GOVERNED BY, THE LAW OF THE STATE OF NEW YORK.**

(e) **Affirmation of Obligations**. Notwithstanding that such consent is not required under the Guaranties, each of the Guarantors consents to the execution and delivery of this Amendment by the parties hereto. As a material inducement to the undersigned to amend the Agreement as set forth herein, each of the Guarantors respectively (i) acknowledges and confirms the continuing existence, validity and effectiveness of the Guaranty to which it is a party, and (ii) agrees that the execution, delivery and performance of this Amendment shall not in any way release, diminish, impair, reduce or otherwise affect its obligations thereunder.

(f) **FINAL AGREEMENT. THIS AMENDMENT, TOGETHER WITH THE AGREEMENT AND THE OTHER LOAN DOCUMENTS, REPRESENTS THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS, OR SUBSEQUENT ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN THE PARTIES.**

(g) **Consent to Amendment to Bank Agreement.** Each Holder hereby consents to the terms of the Amendment to Bank Agreement.

***{Remainder of this page blank; signature page follows.}***

If you agree to the terms and provisions hereof, please evidence your agreement by executing and returning at least one counterpart to the Company at 2501 Cedar Springs, Suite 600, Dallas, Texas 85201.

Very truly yours,

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC,
its general partner

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

**Agreed to as of the Amendment No. 4 Effective Date:**

PRUDENTIAL INVESTMENT MANAGEMENT, INC.

By: /s/ Timothy M. Laczowski
Vice President

THE PRUDENTIAL INSURANCE COMPANY OF AMERICA

By: /s/ Timothy M. Laczowski
Vice President

PRUCO LIFE INSURANCE COMPANY

By: /s/ Timothy M. Laczowski
Vice President

PRUCO LIFE INSURANCE COMPANY OF NEW JERSEY

By: /s/ Timothy M. Laczowski
Vice President

GIBRALTAR LIFE INSURANCE CO., LTD.

By: Prudential Investment Management (Japan), Inc.,
as Investment Manager

By: Prudential Investment Management, Inc.,
as Sub-Adviser

By: /s/ Timothy M. Laczowski
Vice President

RGA REINSURANCE COMPANY

By: Prudential Private Placement Investors,
L.P. (as Investment Advisor)

By: Prudential Private Placement Investors, Inc.
(as its General Partner)

By: /s/ Timothy M. Laczowski
Vice President

CONNECTICUT GENERAL LIFE INSURANCE COMPANY

By: Prudential Investment Management, Inc.,
as Investment Manager

By: /s/ Timothy M. Laczowski
Vice President

ZURICH AMERICAN INSURANCE COMPANY

By: Prudential Private Placement Investors,
L.P. (as Investment Advisor)

By: Prudential Private Placement Investors, Inc.
(as its General Partner)

By: /s/ Timothy M. Laczowski
Vice President

THE PRUDENTIAL LIFE INSURANCE COMPANY, LTD.

By: Prudential Investment Management (Japan), Inc.,
as Investment Manager

By: Prudential Investment Management, Inc.,
as Sub-Adviser

By: /s/ Timothy M. Laczowski
Vice President

PRUDENTIAL RETIREMENT INSURANCE AND ANNUITY COMPANY

By: Prudential Investment Management, Inc.,
as investment manager

By: /s/ Timothy M. Laczowski
Vice President

MTL INSURANCE COMPANY

By: Prudential Private Placement Investors, L.P.
(as Investment Advisor)

By: Prudential Private Placement Investors, Inc.
(as its General Partner)

By: /s/ Timothy M. Laczowski
Vice President

ING USA ANNUITY AND LIFE INSURANCE COMPANY
ING LIFE INSURANCE AND ANNUITY COMPANY
RELIASTAR LIFE INSURANCE COMPANY
SECURITY LIFE OF DENVER INSURANCE COMPANY

By: ING Investment Management LLC, as Agent

By: /s/ Christopher P. Lyons
Name: Christopher P. Lyons
Title Senior Vice President

JOHN HANCOCK LIFE INSURANCE COMPANY

By: /s/ Adam T. Wise
Name: Adam T. Wise
Title: Director

JOHN HANCOCK VARIABLE LIFE INSURANCE COMPANY

By: /s/ Adam T. Wise
Name: Adam T. Wise
Title: Authorized Signatory

JOHN HANCOCK LIFE INSURANCE COMPANY (U.S.A.)

By: /s/ Adam T. Wise
Name: Adam T. Wise
Title: Authorized Signatory

SIGNATURE 7 L.P.

By: Hancock Capital Investment Management, LLC,
as Portfolio Advisor

By: /s/ E. Kendall Hines, Jr.
Name: E. Kendall Hines, Jr.
Title: Senior Managing Director

GENWORTH LIFE AND ANNUITY INSURANCE COMPANY
(as successor by merger to First Colony Life Insurance Company)

By: /s/ John R. Endres

Name: John R. Endres
Title: Investment Officer

**TEACHERS INSURANCE AND ANNUITY ASSOCIATION OF AMERICA**

By: /s/ Lisa M. Ferraro
Name: LISA M. FERRARO
Title: DIRECTOR

METROPOLITAN LIFE INSURANCE COMPANY

METLIFE INVESTORS USA INSURANCE COMPANY
by Metropolitan Life Insurance Company, its investment manager

METLIFE INSURANCE COMPANY OF CONNECTICUT
by Metropolitan Life Insurance Company, its investment manager

METLIFE LIFE AND ANNUITY COMPANY OF CONNECTICUT
by Metropolitan Life Insurance Company, its investment manager

By: /s/ Judith A. Gulotta
Name: Judith A. Gulotta
Title: Managing Director

(executed by Metropolitan Life Insurance Company (i) as to itself as a Purchaser and (ii) as investment manager to MetLife Investors USA Insurance Company as a Purchaser, MetLife Insurance Company of Connecticut as a Purchaser and MetLife Life and Annuity Company of Connecticut as a Purchaser)

**Agreed to and acknowledged by each of the undersigned for the purposes set forth in paragraphs 4 and 5(e) hereof:**

GUARANTORS:

CROSSTEX ACQUISITION MANAGEMENT, L.P.
CROSSTEX MISSISSIPPI PIPELINE, L.P.
CROSSTEX ALABAMA GATHERING SYSTEM, L.P.
CROSSTEX MISSISSIPPI INDUSTRIAL GAS SALES, L.P.
CROSSTEX GULF COAST TRANSMISSION LTD.
CROSSTEX GULF COAST MARKETING LTD.
CROSSTEX CCNG GATHERING LTD.
CROSSTEX CCNG PROCESSING LTD.
CROSSTEX CCNG TRANSMISSION LTD.
CROSSTEX TREATING SERVICES, L.P.
CROSSTEX NORTH TEXAS PIPELINE, L.P.
CROSSTEX NORTH TEXAS GATHERING, L.P.
CROSSTEX NGL MARKETING, L.P.
CROSSTEX NGL PIPELINE, L.P.

By: Crosstex Energy Services GP, LLC
Sole General Partner of each above limited partnership

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

CROSSTEX ENERGY SERVICES, L.P.

By: Crosstex Operating GP, LLC,
its general partner

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

CROSSTEX OPERATING GP, LLC
CROSSTEX ENERGY SERVICES GP, LLC
CROSSTEX LIG, LLC
CROSSTEX TUSCALOOSA, LLC
CROSSTEX LIG LIQUIDS, LLC
CROSSTEX PROCESSING SERVICES, LLC
CROSSTEX PELICAN, LLC

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

SABINE PASS PLANT FACILITY JOINT VENTURE

By: Crosstex Processing Services, LLC,
as general partner
and
By: Crosstex Pelican, LLC, as general partner

By: /s/ Michael Garberding
Name: Michael Garberding
Title: Vice President — Finance

Exhibit A

Holders

PRUDENTIAL INVESTMENT MANAGEMENT, INC.
THE PRUDENTIAL INSURANCE COMPANY OF AMERICA
PRUCO LIFE INSURANCE COMPANY
PRUCO LIFE INSURANCE COMPANY OF NEW JERSEY
GIBRALTAR LIFE INSURANCE CO., LTD.
RGA REINSURANCE COMPANY
CONNECTICUT GENERAL LIFE INSURANCE COMPANY
ZURICH AMERICAN INSURANCE COMPANY
THE PRUDENTIAL LIFE INSURANCE COMPANY, LTD.
PRUDENTIAL RETIREMENT INSURANCE AND ANNUITY COMPANY
MTL INSURANCE COMPANY
ING USA ANNUITY AND LIFE INSURANCE COMPANY
ING LIFE INSURANCE AND ANNUITY COMPANY
RELIASTAR LIFE INSURANCE COMPANY
SECURITY LIFE OF DENVER INSURANCE COMPANY
JOHN HANCOCK LIFE INSURANCE COMPANY
JOHN HANCOCK VARIABLE LIFE INSURANCE COMPANY
JOHN HANCOCK LIFE INSURANCE COMPANY (U.S.A.)
SIGNATURE 7 L.P.
FIRST COLONY LIFE INSURANCE COMPANY
TEACHERS INSURANCE AND ANNUITY ASSOCIATION OF AMERICA
METROPOLITAN LIFE INSURANCE COMPANY
METLIFE INVESTORS USA INSURANCE COMPANY
METLIFE INSURANCE COMPANY OF CONNECTICUT
METLIFE LIFE AND ANNUITY COMPANY OF CONNECTICUT

**Exhibit 21.1**

**LIST OF SUBSIDIARIES**

| Name of Subsidiary | State of Organization |
|---|---|
| Crosstex Operating GP, LLC | Delaware |
| Crosstex Energy Services GP, LLC | Delaware |
| Crosstex Energy Services, L.P. | Delaware |
| Crosstex Pipeline, LLC | Texas |
| Crosstex Gulf Coast Transmission Ltd. | Texas |
| Crosstex Gulf Coast Marketing Ltd. | Texas |
| Crosstex CCNG Gathering, Ltd. | Texas |
| Crosstex CCNG Transmission, Ltd. | Texas |
| Crosstex CCNG Processing, Ltd. | Texas |
| Crosstex Treating Services, L.P. | Delaware |
| Crosstex Alabama Gathering System, L.P. | Delaware |
| Crosstex Mississippi Industrial Gas Sales, L.P. | Delaware |
| Crosstex Mississippi Pipeline, L.P. | Delaware |
| Crosstex Acquisition Management, L.P. | Delaware |
| Crosstex Louisiana Energy, L.P. | Delaware |
| LIG Chemical GP, LLC | Delaware |
| LIG Chemical, L.P. | Delaware |
| LIG Liquids Holdings, L.P. | Delaware |
| Crosstex LIG, LLC | Louisiana |
| Crosstex Tuscaloosa, LLC | Louisiana |
| Crosstex LIG Liquids, LLC | Louisiana |
| Crosstex DC Gathering Company, J.V. | Texas |
| Crosstex North Texas Pipeline, L.P. | Texas |
| Crosstex North Texas Gathering, L.P. | Texas |
| Crosstex Pelican, LLC | Delaware |
| Crosstex Processing Services, LLC | Delaware |
| Crosstex NGL Marketing, L.P. | Texas |
| Crosstex NGL Pipeline, L.P. | Texas |
| Sabine Pass Plant Facility, J.V. | Texas |

**Exhibit 23.1**

**Consent of Independent Registered Public Accounting Firm**

The Partners
Crosstex Energy, L.P.

We consent to the incorporation by reference in the registration statements No. 333-134712 and 333-135951 on Forms S-3 and on registration statements No. 333-107025 and 333-127645 on Forms S-8 of Crosstex Energy, L.P. and subsidiaries of our reports dated March 2, 2009, with respect to the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2008, the related financial statement schedule, and the effectiveness of internal control over financial reporting as of December 31, 2008, which reports appear in the December 31, 2008 annual report on Form 10-K of Crosstex Energy, L.P. and subsidiaries.

/s/ KPMG LLP

Dallas, TX
March 2, 2009

**Exhibit 23.2**

**Consent of Independent Registered Public Accounting Firm**

The Partners of
Crosstex Energy, L.P.:

We consent to the incorporation by reference in the registration statements on Forms S-8 (Nos. 333-107025 and 333-127645) and Forms S-3 (Nos. 333-116538, 333-128282, 333-134712 and 333-135951) of Crosstex Energy, L.P. of our report dated March 2, 2009, with respect to the consolidated balance sheet of Crosstex Energy GP, L.P. as of December 31, 2008, which report appears herein this Form 10-K of Crosstex Energy, L.P.

/s/ KPMG LLP

Dallas, TX
March 2, 2009

**Exhibit 31.1**

**CERTIFICATIONS**

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

1. I have reviewed this annual report on Form 10-K 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 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: March 2, 2009

**Exhibit 31.2**

**CERTIFICATIONS**

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

1. I have reviewed this annual report on Form 10-K 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 case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

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

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

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

/s/ William W. Davis

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

Date: March 2, 2009

**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 Annual Report of Crosstex Energy, L.P. (the "Registrant") on Form 10-K for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

/s/ Barry E. Davis
Barry E. Davis
*President and Chief Executive Officer*

March 2, 2009

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

March 2, 2009

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.

**Exhibit 99.1**

**Report of Independent Registered Public Accounting Firm**

The Partners
Crosstex Energy GP, L.P.:

We have audited the accompanying consolidated balance sheet of Crosstex Energy GP, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2008. This consolidated financial statement is the responsibility of the Partnership's management. Our responsibility is to express an opinion on this consolidated financial statement based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. An audit of a balance sheet includes examining, on a test basis, evidence supporting the amounts and disclosures in that balance sheet, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

In our opinion, the consolidated balance sheet referred to above presents fairly, in all material respects, the financial position of Crosstex Energy GP, L.P. and subsidiaries as of December 31, 2008, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Dallas, Texas
March 2, 2009

**CROSSTEX ENERGY GP, L.P.**
**Consolidated Balance Sheet**
**December 31, 2008**
**(In thousands)**

**ASSETS**

| | |
|---|---|
| Current assets: | |
| Cash and cash equivalents | $ 1,636 |
| Accounts receivable: | |
| Trade, net of allowance for bad debts of $3,655 | 49,185 |
| Accrued revenues | 292,668 |
| Imbalances | 3,893 |
| Affiliated companies | 110 |
| Note receivable | 375 |
| Other | 7,243 |
| Fair value of derivative assets | 27,166 |
| Natural gas and natural gas liquids, prepaid expenses, and other | 9,645 |
| Total current assets | 391,921 |
| Property and equipment: | |
| Transmission assets | 474,771 |
| Gathering systems | 614,572 |
| Gas plants | 577,250 |
| Other property and equipment | 70,618 |
| Construction in process | 86,462 |
| Total property and equipment | 1,823,673 |
| Accumulated depreciation | (296,393) |
| Total property and equipment, net | 1,527,280 |
| Fair value of derivative assets | 4,628 |
| Intangible assets, net of accumulated amortization of $89,231 | 578,096 |
| Goodwill | 19,673 |
| Other assets, net | 11,668 |
| Total assets | $ 2,533,266 |
| **LIABILITIES AND PARTNERS' EQUITY** | |
| Current liabilities: | |
| Drafts payable | $ 21,514 |
| Accounts payable | 23,879 |
| Accrued gas purchases | 270,229 |
| Accrued imbalances payable | 7,100 |
| Fair value of derivative liabilities | 28,506 |
| Current portion of long-term debt | 9,412 |
| Other current liabilities | 64,191 |
| Total current liabilities | 424,831 |
| Long-term debt | 1,254,294 |
| Other long-term liabilities | 24,708 |
| Deferred tax liability | 8,727 |
| Fair value of derivative liabilities | 22,775 |
| Minority Interest | 781,126 |
| Commitments and contingencies | — |
| Partners' equity | 16,805 |
| Total liabilities and partners' equity | $ 2,533,266 |

See accompanying notes to consolidated balance sheet.

**(1) Organization and Summary of Significant Agreements**

***(a) Description of Business***

Crosstex Energy GP, L.P. (the General Partner) is a Delaware limited partnership formed on July 12, 2002 to become the General Partner of Crosstex Energy, L.P. The General Partner is an indirect wholly-owned subsidiary of Crosstex Energy, Inc. (CEI). The General Partner owns a 2% general partner interest in Crosstex Energy, L.P. (CELP). CELP is engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids or NGLs. CELP connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of NGLs, transports natural gas and NGLs and ultimately provides an aggregated supply of natural gas and NGLs to a variety of markets. In addition, CELP purchases natural gas and NGLs from producers not connected to its gathering systems for resale and markets natural gas and NGLs on behalf of producers for a fee.

***(b) Partnership Ownership***

Crosstex Energy GP, L.P., the general partner of the Partnership, is an indirect wholly-owned subsidiary of Crosstex Energy, Inc. (CEI). As of December 31, 2008, CEI owns 16,414,830 common units in the Partnership through its wholly-owned subsidiaries. As of December 31, 2008, CEI owned 34.0% of the limited partner interests in the Partnership and officers and directors owned 1.02% of the limited partnership interests. The remaining units are held by the public.

***(c) Basis of Presentation***

The accompanying consolidated balance sheet includes the assets and liabilities of operations of the General Partner and CELP. The General Partner has no independent operations and no material assets outside of its interest in CELP. The General Partner proportionately consolidates CELP's undivided 59.27% interest in a gas plant acquired by CELP in November 2005 (23.85%) and May 2006 (35.42%). The General Partner also consolidates CELP's joint venture interest in Crosstex DC Gathering, J.V. (CDC) as discussed more fully in Note 3, in accordance with FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities* (FIN No. 46R). The consolidated operations are hereafter referred to herein collectively as the "Partnership." All material intercompany balances and transactions have been eliminated.

**(2) Significant Accounting Policies**

***(a) Management's Use of Estimates***

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

***(b) Cash and Cash Equivalents***

The Partnership considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

***(c) Natural Gas and Natural Gas Liquids Inventory***

The Partnership's inventories of products consist of natural gas and NGLs. The Partnership reports these assets at the lower of cost or market.

***(d) Property, Plant, and Equipment***

Property, plant and equipment consist of intrastate gas transmission systems, gas gathering systems, industrial supply pipelines, NGL pipelines, natural gas processing plants, NGL fractionation plants, dew point control and gas treating plants.

Other property and equipment is primarily comprised of computer software and equipment, furniture, fixtures, leasehold improvements and office equipment. Property, plant and equipment are recorded at cost. Gas required to maintain pipeline minimum

pressures is capitalized and classified as property, plant and equipment. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest costs are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use.

Depreciation is provided using the straight-line method based on the estimated useful life of each asset, as follows:

| | Useful Lives |
|---|---|
| Transmission assets | 15-30 years |
| Gathering systems | 7-15 years |
| Gas treating and gas processing plants | 15 years |
| Other property and equipment | 3-10 years |

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset.

When determining whether impairment of one of our long-lived assets has occurred, the Partnership must estimate the undiscounted cash flows attributable to the asset. The Partnership's estimate of cash flows is based on assumptions regarding the purchase and resale margins on natural gas, volume of gas available to the asset, markets available to the asset, operating expenses, and future natural gas prices and NGL product prices. The amount of availability of gas to an asset is sometimes based on assumptions regarding future drilling activity, which may be dependent in part on natural gas prices. Projections of gas volumes and future commodity prices are inherently subjective and contingent upon a number of variable factors. Any significant variance in any of the above assumptions or factors could materially affect our cash flows, which could require us to record an impairment of an asset.

The Partnership recorded impairments to long-lived assets of $25.6 million during the year ending December 31, 2008. No impairments were incurred during the years ended December 31, 2007 and 2006.

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, also requires long-lived assets being held for sale or disposed of to be presented in the financial statements separately. During the third quarter of 2008 the Partnership held for sale its undivided 12.4% interest in the Seminole gas processing plant. The sale was finalized on November 17, 2008.

During 2008 CEI transferred the Clarkson and Jonesville plants to the Partnership at net book value for a cash price of $0.4 million which represented the fair value of the plants.

***(e) Goodwill and Intangibles***

The Partnership has approximately $19.7 million of goodwill at December 31, 2008. Goodwill created in the formation of the Partnership of $4.9 net book value associated with the Midstream assets was impaired during the year ended December 31, 2008. The goodwill remaining in the Partnership is associated with the Treating assets. Goodwill will continue to be assessed at least annually for impairment.

Intangible assets consist of customer relationships and the value of the dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems. The Chief acquisition, included $395.6 million of such intangibles, including the Devon Energy Corporation (Devon) gas gathering agreement. Intangible assets other than the intangibles associated with the Chief acquisition are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from three to 15 years. The intangible assets associated with the Chief acquisition are being amortized using the units of throughput method of amortization.

***(f) Other Assets***

Unamortized debt issuance costs totaling $11.7 million at December 31, 2008 are included in other noncurrent assets. Debt issuance costs are amortized into interest expense using the effective-interest method over the term of the debt for the senior secured

notes. Debt issuance costs are amortized using the straight-line method over the term of the debt for the bank credit facility because borrowings under the bank credit facility cannot be forecasted for an effective-interest computation.

***(g) Gas Imbalance Accounting***

Quantities of natural gas over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. The Partnership had imbalance payables of $7.1 million at December 31, 2008 which approximates the fair value of these imbalances. The Partnership had imbalance receivables of $3.9 million at December 31, 2008 which are carried at the lower of cost or market value.

***(h) Asset Retirement Obligations***

In March 2005, the FASB issued Interpretation No. 47, "*Accounting for Conditional Asset Retirement Obligations*" (FIN 47) which became effective at December 31, 2005. FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, "*Accounting for Asset Retirement Obligations*", refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FIN 47 provides that a liability for the fair value of a conditional asset retirement activity should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB Statement No. 143. The Partnership did not provide any asset retirement obligations as of December 31, 2008 because it does not have sufficient information as set forth in FIN 47 to reasonably estimate such obligations and the Partnership has no current intention of discontinuing use of any significant assets.

***(i) Revenue Recognition***

The Partnership recognizes revenue for sales or services at the time the natural gas, or NGLs are delivered or at the time the service is performed. The Partnership generally accrues one to two months of sales and the related gas purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates. The Partnership's purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the statements of operations in accordance with EITF Issue No. 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Except for fee based arrangements and the Partnership's energy trading activities related to its "off-system" gas marketing operations discussed in Note 2(k), the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, schedules the transportation and assumes credit risk.

The Partnership accounts for taxes collected from customers attributable to revenue transactions and remitted to government authorities on a net basis (excluded from revenues).

***(j) Derivatives***

The Partnership uses derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities",* requires that all derivatives be recorded on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the differences between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instrument is recorded on the balance sheet as fair value of derivative assets or liabilities.

Realized and unrealized gains and losses on derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, are recorded as gain or loss on derivatives in the consolidated statement of operations. Unrealized gains and losses on effective cash flow derivatives are recorded as a component of accumulated other comprehensive income. When the hedged transaction occurs, the realized gain or loss on the hedge derivative is transformed from accumulated other comprehensive income to earnings. Realized gains and losses on commodity hedge derivatives are recognized in revenues, and realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

***(k) Legal Costs Expected to be Incurred in Connection with a Loss contingency***

Legal costs incurred in connection with a loss contingency are expensed as incurred.

***(l) Income Taxes***

The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The net tax basis in the Partnership's assets and liabilities is less than the reported amounts on the financial statements by approximately $437.2 million as of December 31, 2008. Effective January 1, 2007, the Partnership is subject to the margin tax enacted by the state of Texas on May 1, 2006.

The LIG entities the Partnership formed to acquire the stock of LIG Pipeline Company and its subsidiaries, are treated as taxable corporations for income tax purposes. The entity structure was formed to effect the matching of the tax cost to the Partnership of a step-up in the basis of the assets to fair market value with the recognition of benefits of the step-up by the Partnership. A deferred tax liability of $8.2 million was recorded at the acquisition date. The deferred tax liability represents future taxes payable on the difference between the fair value and tax basis of the assets acquired. The Partnership, through ownership of the LIG entities, generated a net operating loss of $4.8 million during 2005 as a result of a tax loss on a property sale of which $0.9 million was carried back to 2004, $1.9 million was utilized in 2006 and substantially all of the remaining $2.0 million was utilized in 2007.

The Partnership provides for income taxes using the liability method. The principal component of the Partnership's net deferred tax liability is as follows of December 31, 2008 (in thousands):

| | |
|---|---|
| Deferred income tax assets: | |
| Net operating loss carryforward — current | $ 41 |
| Net operating loss carryforward — long-term | — |
| Alternative minimum tax credit carryover — long-term | — |
| | $ 41 |
| Deferred income tax liabilities: | |
| Property, plant, equipment, and intangible assets-current. | $ (501) |
| Property, plant, equipment and intangible assets-long-term | (8,727) |
| | (9,228) |
| Net deferred tax liability | $ (9,187) |

A net current deferred tax liability of $0.5 million is included in other current liabilities.

The Partnership adopted the provisions of FASB Interpretation No. 48,*Accounting for Uncertainty in Income Taxes,* on January 1, 2007. A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (in thousands):

| | |
|---|---|
| Balance as of December 31, 2007 | $ — |
| Increases related to prior year tax positions | 904 |
| Increases related to current year tax positions | 717 |
| Balance as of December 31, 2008 | $ 1,621 |

Unrecognized tax benefits of $1.6 million, if recognized, would affect the effective tax rate. We do not expect any material change in the balance of our unrecognized tax benefits over the next twelve months. In the event interest or penalties are incurred with respect to income tax matters, our policy will be to include such items in income tax expense. At December 31, 2008, tax years 2005 through 2008 remain subject to examination by the Internal Revenue Service and applicable states.

***(m) Environmental Costs***

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or discounted when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated.

***(n) Cash Distributions***

Unless restricted by the terms of our credit facility, CELP must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter. Distributions will generally be made 98% to the common and subordinated unitholders and 2% to the General Partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. CELP's senior secured credit facility prohibits CELP from declaring distributions to unitholders if any event of default exists or would result from the declaration of distributions.

Under the quarterly incentive distribution provisions, generally the General Partner is entitled to 13% of amounts CELP distributes in excess of $0.25 per unit, 23% of the amounts CELP distributes in excess of $0.3125 per unit and 48% of amounts CELP distributes in excess of $0.375 per unit. Incentive distributions totaling $30.8 million were earned by the General Partner for the year ended December 31, 2008. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter. CELP paid annual per common unit distributions of $2.28 for the year ended December 31, 2008.

See Note (4) for a description of the bank credit facilities, which restrict the Partnership's ability to make future distributions.

***(o) Minority Interest***

Minority interest represents third party ownership interests in the net assets of our subsidiaries that primarily include the limited partners of CELP and CELP's joint venture partner. For financial reporting purposes, the assets and liabilities of our majority owned subsidiaries are consolidated with those of our own, with any third party ownership interest in such amounts presented as minority interest.

***(p) Option Plans***

Effective January 1, 2006, the Partnership adopted the provisions of SFAS No. 123R, *"Share-Based Payment"* (FAS No. 123R) which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements.

The Partnership elected to use the modified-prospective transition method for adopting SFAS No. 123R. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under SFAS No. 123R. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with SFAS No.123R. Under SFAS No.123R, the Partnership is required to estimate forfeitures in determining periodic compensation cost.

The Partnership and CEI each have similar unit or share-based payment plans for employees. Share-based compensation associated with the CEI share-based compensation plans awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership.

***(q) Recent Accounting Pronouncements***

In June 2008, the Financial Accounting Standards Board (FASB) issued Staff Position FSP EITF 03-6-1 (the FSP) which requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in EITF Issue No. 03-6, "Participating Securities and the Two-Class Method under FASB Statement No. 128," and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB Statement No. 128, *Earnings per Share.* The FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Upon adoption, the Partnership will consider restricted shares with nonforfeitable dividend rights in the calculation of earnings per share and will adjust all prior reporting periods retrospectively to conform to the requirements, although the impact should not be material.

In February 2007, the FASB issued SFAS No. 159,*"Fair Value Option for Financial Assets and Financial Liabilities-Including an amendment to FASB Statement No. 115"* (SFAS 159) permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons

between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. The adoption of SFAS 159 will have no material impact on our financial statements.

In December 2007, the FASB issued SFAS No. 141R, *"Business Combinations"* (SFAS 141R) and SFAS No. 160, *"Noncontrolling Interests in Consolidated Financial Statements"* (SFAS 160). SFAS 141R requires most identifiable assets, liabilities, noncontrolling interests and goodwill acquired in a business combination to be recorded at "full fair value." The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under SFAS 141R, all business combinations will be accounted for by applying the acquisition method. SFAS 141R is effective for periods beginning on or after December 15, 2008. SFAS 160 will require noncontrolling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for noncontrolling interests and transactions with noncontrolling interest holders in consolidated financial statements. SFAS 160 is effective for periods beginning on or after December 15, 2008 and will be applied prospectively to all noncontrolling interests, including any that arose before the effective date except that comparative period information must be recast to classify noncontrolling interests in equity, attribute net income and other comprehensive income to noncontrolling interests, and provide other disclosures required by SFAS 160.

In May 2008, the FASB issued SFAS No. 162,*The Hierarchy of Generally Accepted Accounting Principles*("SFAS No. 162"). SFAS No. 162 is intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States of America. SFAS No. 162 will be effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board Auditing amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*. The Partnership is currently evaluating the potential impact, if any, of the adoption of SFAS No. 162 on our consolidated financial statements.

In March of 2008, the FASB issued SFAS No. 161,*"Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133"*(SFAS 161). SFAS 161 requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under SFAS 133 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. SFAS 161 is effective for fiscal years beginning after November 15, 2008. The principal impact to the Partnership will be to require expanded disclosure regarding derivative instruments.

**(3) Investment in Joint Venture and Note Receivable**

The Partnership owns a majority interest in Crosstex Denton County Joint Venture (CDC) and consolidates its investment in CDC pursuant to FIN No. 46R. The Partnership manages the business affairs of CDC. The other joint venture partner (the CDC partner) is an unrelated third party who owns and operates a natural gas field located in Denton County, Texas.

In connection with the formation of CDC, the Partnership agreed to loan the CDC partner up to $1.5 million for its initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to the Partnership attributable to CDC partner's share of distributable cash flow to repay the loan. The balance remaining on the note of $0.4 million is included in current notes receivable as of December 31, 2008.

**(4) Long-Term Debt**

As of December 31, 2008, long-term debt consisted of the following (in thousands):

| | |
|---|---|
| Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rate at December 31, 2008 was 6.33% | $ 784,000 |
| Senior secured notes, weighted average interest rate at December 31, 2008 of 8.0% | 479,706 |
| | 1,263,706 |
| Less current portion | (9,412) |
| Debt classified as long-term | $ 1,254,294 |

*Credit Facility.* In September 2007, the Partnership increased borrowing capacity under the bank credit facility to $1.185 billion. The bank credit facility matures in June 2011. As of December 31, 2008, $850.4 million was

outstanding under the bank credit facility, including $66.4 million of letters of credit, leaving approximately $334.6 million available for future borrowing.

Obligations under the bank credit facility are secured by first priority liens on all of the Partnership's material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of the Partnership's equity interests in substantially all of its subsidiaries, and rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by the Partnership's material subsidiaries. The Partnership 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.

On November 7, 2008, the Partnership entered into the Fifth Amendment and Consent (the "Fifth Amendment") to its credit facility with Bank of America, N.A., as administrative agent, and the banks and other parties thereto (the "Bank Lending Group"). The Fifth Amendment amended the agreement governing its credit facility to, among other things, (i) increase the maximum permitted leverage ratio it must maintain for the fiscal quarters ending December 31, 2008 through September 30, 2009, (ii) lower the minimum interest coverage ratio it must maintain for the fiscal quarter ending December 31, 2008 and each fiscal quarter thereafter, (iii) permit it to sell certain assets, including the non-strategic asset dispositions (iv) increase the interest rate it pays on the obligations under the credit facility and (v) lower the maximum permitted leverage ratio it must maintain if the Partnership or its subsidiaries incur unsecured note indebtedness.

Due to the continued decline in commodity prices and the deterioration in the processing margins, the Partnership determined that there was a significant risk that the amended terms negotiated in November 2008 would not be sufficient to allow it to operate during 2009 without triggering a default under its bank facility and the senior secured note agreement. On February 27, 2009, the Partnership entered into the Sixth Amendment to the Fourth Amended and Restated Credit Agreement and Consent (the "Sixth Amendment") to its credit facility with Bank Lending Group. Under the Sixth Amendment, borrowings will bear interest at its option at the administrative agent's reference rate plus an applicable margin or London Interbank Offering Rate (LIBOR) plus an applicable margin. The applicable margins for the Partnership's interest rate and letter of credit fees vary quarterly based on the Partnership's leverage ratio as defined by the credit facility (the "Leverage Ratio" being generally computed as total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows beginning February 27, 2009:

| Leverage Ratio | Bank Reference Rate Advances(a) | LIBOR Rate Advances(b) | Letter of Credit Fees(c) | Commitment Fees(d) |
|---|---|---|---|---|
| Greater than or equal to 5.00 to 1.00 | 3.00% | 4.00% | 4.00% | 0.50% |
| Greater than or equal to 4.25 to 1.00 and less than 5.00 to 1.00 | 2.50% | 3.50% | 3.50% | 0.50% |
| Greater than or equal to 3.75 to 1.00 and less than 4.25 to 1.00 | 2.25% | 3.25% | 3.25% | 0.50% |
| Less than 3.75 to 1.00 | 1.75% | 2.75% | 2.75% | 0.50% |

(a) The applicable margins for the bank reference rate advances ranged from 0% to 0.25% under the bank credit facility prior to the Fifth and Sixth Amendments. The applicable margin for the bank reference rate advances was paid at the maximum rate of 2.00% under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(b) The applicable margins for the LIBOR rate advances ranged from 1.00% to 1.75% under the bank credit facility prior to the Fifth and Sixth Amendments. The applicable margin for the bank reference rate advances was paid at the maximum rate of 3.00% under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(c) The letter of credit fees ranged from 1.00% to 1.75% per annum plus a fronting fee of 0.125% per annum under the bank credit facility prior to the Fifth and Sixth Amendments. The letter of credit fees were paid at the maximum rate of 3.00% per annum in addition to the fronting fee under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

(d) The commitment fees ranged from 0.20% to 0.375% per annum on the unused amount of the credit facility under the bank credit facility prior to the Fifth and Sixth Amendments. The commitment fees were paid at the maximum rate of 0.50% per annum under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

The Sixth Amendment also sets a floor for the LIBOR interest rate of 2.75% per annum , which means, effective as of February 27, 2009, borrowings under the bank credit facility accrue interest at the rate of 6.75% based on the LIBOR rate in effect on such date and the Partnership's current leverage ratio. Based on the Partnership's forecasted leverage ratios for 2009, it expects the applicable margins to be at the high end of these ranges for its interest rate and letter of credit fees.

Pursuant to the Sixth Amendment, the Partnership must pay a leverage fee if it does not prepay debt and permanently reduce the banks' commitments by the cumulative amounts of $100.0 million on September 30, 2009, $200.0 million on December 31, 2009, and $300.0 million on March 31, 2010. If the Partnership fails to meet any de-leveraging target, the Partnership must pay a leverage fee on such date, equal to the product of the aggregate commitments outstanding under its bank credit facility and the outstanding amount of senior secured note agreement on such date, and 1.0% on September 30, 2009, 1.0% on December 31, 2009, and 2.0% on March 31, 2010. This leverage fee will accrue on the applicable date, but not be payable until the Partnership refinances its bank credit facility.

Under the Sixth Amendment, the maximum Leverage Ratio is as follows:

- 7.25 to 1.00 for the fiscal quarter ending March 31, 2009;
- 8.25 to 1.00 for the fiscal quarters ending June 30, 2009 and September 30, 2009;
- 8.50 to 1.00 for the fiscal quarter ending December 31, 2009;
- 8.00 to 1.00 for the fiscal quarter ending March 31, 2010;
- 6.65 to 1.00 for the fiscal quarter ending June 30, 2010;
- 5.25 to 1.00 for the fiscal quarter ending September 30, 2010;
- 5.00 to 1.00 for the fiscal quarter ending December 31, 2010;
- 4.50 to 1.00 for any fiscal quarters ending March 31, 2011 through March 31, 2012; and
- 4.25 to 1.00 for any fiscal quarters ending June 30, 2012 and thereafter..

The minimum cash interest coverage ratio (as defined in the agreement, measured quarterly on a rolling four-quarter basis) is as follows under the Sixth Amendment:

- 1.75 to 1.00 for the fiscal quarters ending March 31, 2009;
- 1.50 to 1.00 for the fiscal quarter ending June 30, 2009;
- 1.30 to 1.00 for the fiscal quarter ending September 30, 2009;
- 1.15 to 1.00 for the fiscal quarter ending December 31, 2009;
- 1.25 to 1.00 for the fiscal quarter ending March 31, 2010;
- 1.50 to 1.00 for the fiscal quarter ending June 30, 2010;
- 1.75 to 1.00 for any fiscal quarter ending September 30, 2010 and December 31, 2010; and
- 2.50 to 1.00 for any fiscal quarter ending March 31, 2011 and thereafter.

Under the Sixth Amendment, no quarterly distributions may be paid to partners unless the PIK notes have been repaid and the Leverage Ratio is less than 4.25 to 1.00. If the Leverage Ratio is between 4.00 to 1.00 and 4.25 to 1.00, the Partnership may make the minimum quarterly distribution of up to $0.25 per unit if the PIK notes have been repaid. If the Leverage Ratio is less than 4.00 to 1.00, the Partnership may make quarterly distributions to partners from available cash as provided by its partnership agreement if the PIK notes have been repaid. The PIK notes are due six months after the earlier of the refinancing or maturity of the bank credit facility. Based on its forecasted leverage ratios for 2009 and the Partnership's near term ability to refinance its bank credit facility, the Partnership does not anticipate making quarterly distributions during 2009 other than the distribution paid in February 2009 related to fourth quarter 2008 operating results. The Partnership will not be able to make distributions to its unitholders in future periods if its leverage ratio does not improve.

The Sixth Amendment also limits the Partnership's annual capital expenditures (excluding maintenance capital expenditures) to $120.0 million in 2009 and $75.0 million in 2010 and each year thereafter (with unused amounts in any year being carried forward to the next year). It is unlikely that the Partnership will be able to make any acquisitions based on the terms of our credit facility and the current condition of the capital markets because it may only use a portion of the proceeds from the incurrence of unsecured debt and the issuance of equity to make such acquisitions.

The Sixth Amendment also eliminated the accordion in our bank credit facility, which previously had permitted us to increase commitments thereunder by certain amounts if any bank was willing to undertake such commitment increase.

The Sixth Amendment also revised the terms for mandatory repayment of outstanding indebtedness from asset sales and proceeds from incurrence of unsecured debt and equity issuances. Proceeds from debt issuances and equity issuances not required to prepay indebtedness are considered to be "Excess Proceeds" under the amended bank credit agreement. The Partnership may retain all Excess Proceeds. The following table sets forth the amended prepayment terms:

| Leverage Ratio* | % of Net Proceeds from Asset Sales Required for Prepayment | % of Net Proceeds from Debt Issuances Required for Prepayment | % of Net Proceeds from Equity Issuance Required for Prepayment |
|---|---|---|---|
| Greater than or equal to 4.50 | 100% | 100% | 50% |
| Greater or equal to 3.50 and Less Than 4.50 | 100% | 50% | 25% |
| Less than 3.50 | 100% | 0% | 0% |

* The Leverage Ratio is to be adjusted to give effect to proceeds from debt or equity issuance and the use of such proceeds for each proportional level of Leverage Ratio.

The prepayments are to be applied pro rata based on total debt (including letter of credit obligations) outstanding under the bank credit agreement and the total debt outstanding under the note agreement described below. Any prepayments of advances on the bank credit facility from proceeds from asset sales, debt or equity issuances will permanently reduce the borrowing capacity or commitment under the facility in an amount equal to 100% of the amount of the prepayment. Any such commitment reduction will not reduce the banks' $300.0 million commitment to issue letters of credit.

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

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- change the nature of its business;
- enter into certain commodity contracts;
- make certain amendments to its or the operating partnership's partnership agreement; and
- engage in transactions with affiliates.

Each of the following will be an event of default under the bank credit facility:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;
- certain judgments against us or any of its subsidiaries, in excess of certain allowances;
- certain ERISA events involving the Partnership or its subsidiaries;
- bankruptcy or other insolvency events;
- a change in control (as defined in the credit agreement); and
- the failure of any representation or warranty to be materially true and correct when made.

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under our bank credit facility will immediately become due and payable. If any other event of default exists under the bank credit facility, the lenders may accelerate the maturity of the obligations outstanding under the bank credit facility and exercise other rights and remedies.

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. See Note 8 to the financial statements for a discussion of interest rate swaps.

*Senior Secured Notes.* The Partnership entered into a master shelf agreement with an institutional lender in 2003 that was amended in subsequent years to increase availability under the agreement, pursuant to which it issued the following senior secured notes (dollars in thousands):

| Month Issued | Amount | Interest Rate(1) | Maturity | Principal Payment Terms |
|---|---|---|---|---|
| June 2003(2) | $ 30,000 | 9.45% | 7 years | Quarterly payments of $1,765 from June 2006-June 2010 |
| July 2003(2) | 10,000 | 9.38% | 7 years | Quarterly payments of $588 from July 2006-July 2010 |
| June 2004 | 75,000 | 9.46% | 10 years | Annual payments of $15,000 from July 2010-July 2014 |

| | | | | |
|---|---|---|---|---|
| November 2005 | 85,000 | 8.73% | 10 years | Annual payments of $17,000 from November 2010-December 2014 |
| March 2006 | 60,000 | 8.82% | 10 years | Annual payments of $12,000 from March 2012-March 2016 |
| July 2006 | 245,000 | 8.46% | 10 years | Annual payments of $49,000 from July 2012-July 2016 |
| Total Issued | 505,000 | | | |
| Principal repaid | (25,294) | | | |
| Balance as of December 31, 2008 | $ 479,706 | | | |

(1) Interest rates have been adjusted to give effect to the 2% interest rate increase under the February 27, 2009 described below.

(2) Principal repayments were $19.4 million and $5.9 million on the June 2003 and July 2003 notes, respectively.

On November 7, 2008, the Partnership amended our senior secured note agreements governing its senior secured notes to, among other things, (i) modify the maximum permitted leverage ratio and lower the minimum interest coverage ratio it must maintain consistent with the ratios under the Fifth Amendment to the bank credit facility, (ii) permit it to sell certain assets and (iii) increase the interest rate it pays on the senior secured notes. The interest rate the Partnership paid on the senior secured notes increased by 1.25% for the fourth quarter of 2008 due to this amendment.

The covenants and terms of default for the senior secured notes are substantially the same as the covenants and default terms under its bank credit facility, and therefore the agreement governing the senior secured notes also required amendment in 2009. On February 27, 2009, the Partnership amended its senior note agreement to (i) increase the maximum permitted leverage ratio and to lower the minimum interest coverage ratio it must maintain consistent with the ratios under the Amendment to the bank credit facility, (ii) revise the mandatory prepayment terms consistent with the terms under the Sixth Amendment to the bank credit facility, (iii) increase the interest rate it pays on the senior secured notes, and (iv) provide for the payment of a leverage fee consistent with the terms of the bank credit facility. Commencing February 27, 2009 the interest rate it pays in cash on all of the senior secured notes will increase by 2.25% per annum over the comparative interest rates under the senior note agreements prior to the November and February amendments. As a result of this rate increase, the weighted average interest rate on the outstanding balance on the senior secured notes is approximately 9.25% as of February 2009.

Under the amended senior secured note agreement, the senior secured notes will accrue additional interest of 1.25% per annum of the senior secured note (the “PIK notes”) in the form of an increase in the principal amount unless the Partnership’s leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter. All PIK notes will be payable six months after the maturity of its bank credit facility, which is currently scheduled to mature in June 2011, or six months after refinancing of such indebtedness if prior to the maturity date.

Per the terms of the amended senior note agreement, commencing on the date the Partnership refinances its bank credit facility, the interest rate payable in cash on its senior secured notes will increase by 1.25% per annum for any quarter if its leverage ratio as of the most recently ended fiscal quarter was greater than or equal to 4.25 to 1.00. In addition, commencing on June 30, 2012, the interest rate payable in cash on the Partnership’s senior secured notes will increase by 0.50% per annum for any quarter if its leverage as of the most recently ended fiscal quarter was greater than or equal to 4.00 to 1.00, but this incremental interest will not accrue if the Partnership is paying the incremental 1.25% per annum of interest described in the preceding sentence.

These notes represent the Partnership’s senior secured obligations and will rank *pari passu* in right of payment with the bank credit facility. The notes are secured, on an equal and ratable basis with the Partnership’s obligations under the credit facility, by first priority liens on all of its material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all its equity interests in substantially all of its subsidiaries. The senior secured notes are guaranteed by the Partnership’s material subsidiaries.

The senior secured notes issued in 2003 are redeemable, at the Partnership’s option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the senior secured note agreement. The senior secured notes issued 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance.

If an event of default resulting from bankruptcy or other insolvency events occurs, the senior secured notes will become immediately due and payable. If any other event of default occurs and is continuing, holders of at least 50.1% in principal amount of the outstanding notes may at any time declare all the notes then outstanding to be immediately due and payable. If an event of default relating to the nonpayment of principal, make-whole amounts or interest occurs, any holder of outstanding notes affected by such event of default may declare all the notes held by such holder to be immediately due and payable.

The senior secured note agreement relating to the notes contains substantially the same covenants and events of default as the Partnership's bank credit facility.

The Partnership was in compliance with all debt covenants at December 31, 2008 and expects to be in compliance with debt covenants for the next twelve months.

*Intercreditor and Collateral Agency Agreement.* In connection with the execution of the senior secured note agreement, the lenders under the Partnership's bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by the Partnership and its subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under the Partnership's bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under its bank credit facility and the senior secured note agreement. On February 27, 2009, the holders of the Partnership's senior secured notes and a majority of the banks under its bank credit facility entered into an amendment to the Intercreditor and Collateral Agency Agreement, which provides that the PIK notes and certain treasury management obligations will be secured by the collateral for its bank credit facility and the senior secured notes, but only paid with proceeds of collateral after obligations under its bank credit facility and the senior secured notes are paid in full.

*Maturities*. Maturities for the long-term debt as of December 31, 2008 are as follows (in thousands):

| | |
|---|---|
| 2009 | 9,412 |
| 2010 | 20,294 |
| 2011 | 816,000 |
| 2012 | 93,000 |
| 2013 | 93,000 |
| Thereafter | 232,000 |

**(5) Other Long-Term Liabilities**

The Partnership entered into 9 and 10-year capital leases for certain compressor equipment. Assets under capital leases as of December 31, 2008 are summarized as follows (in thousands):

| | |
|---|---|
| Compressor equipment | $ 28,890 |
| Less: Accumulated amortization | (1,523) |
| Net assets under capital lease. | $ 27,367 |

The following are the minimum lease payments to be made in each of the following years indicated for the capital lease in effect as of December 31, 2008 (in thousands):

| Fiscal Year | |
|---|---|
| 2009 through 2013 | $ 16,150 |
| Thereafter | 16,691 |
| Less: Interest | (5,184) |
| Net minimum lease payments under capital lease | 27,657 |
| Less: Current portion of net minimum lease payments | (3,189) |
| Long-term portion of net minimum lease payments | $ 24,468 |

**(6) Employee Incentive Plans**

***(a) Long-Term Incentive Plan***

The Partnership's managing general partner adopted a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 4,800,000 common unit options and restricted units. The plan is administered by the compensation committee of the managing general partner's board of directors. The units issued upon exercise or vesting are newly issued units.

***(b) Restricted Units***

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the restricted units will become exercisable upon a change of control of the Partnership, its general partner or its general partner's general partner.

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted in 2006, 2007 and 2008 generally cliff vest after three years of service.

**Notes to Consolidated Balance Sheet — (Continued)**

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 year ended December 31, 2008 is provided below:

**Crosstex Energy, L.P. Restricted Units:**

| | Number of Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested, beginning of period | 504,518 | $ 34.29 |
| Granted | 432,354 | 29.60 |
| Vested* | (204,033) | 33.40 |
| Forfeited | (34,273) | 26.69 |
| Reduced estimated performance units | (154,499) | 31.66 |
| Non-vested, end of period | 544,067 | $ 31.90 |
| Aggregate intrinsic value, end of period (in thousands) | $ 2,378 | |

* Vested units include 51,214 units withheld for payroll taxes paid on behalf of employees.

The Partnership's executive officers were granted restricted units during 2008 and 2007, the number of which may increase or decrease based on the accomplishment of certain performance targets based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over a three-year period). The minimum number of restricted units for all executives of 52,795 and 14,319 for 2008 and 2007, respectively, are included in the non-vested end of period units line in the table above. Target performance grants were previously included in the restricted units granted and were included in share-based compensation as it appeared probable that target thresholds would be achieved. However, during the last half of 2008, the Partnership's assets were negatively impacted by hurricanes Gustav and Ike. During this same period the Partnership has also been negatively impacted by declines in natural gas and NGL prices coupled with the global economic decline and the recent tightening of capital markets. The impact of these events was significant enough to make the achievement of target performance goals less than probable. Therefore, an expense of $0.7 million previously recorded for target performance-based restricted units has been retroactively reversed and is shown as a reduction to stock-based compensation expense and a reduction in the number of estimated performance units outstanding of 154,499 units in the year ended December 31, 2008. All performance-based awards greater than the minimum performance grant levels will be subject to reevaluation and adjustment until the restricted units vest. The performance-based restricted units are included in the current share-based compensation calculations as required by SFAS No. 123(R) when it is deemed probable of achieving the performance criteria.

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) are provided below (in thousands):

| Crosstex Energy, L.P. Restricted Units: | Year Ended December 31, 2008 |
|---|---|
| Aggregate intrinsic value of units vested | $ 5,907 |
| Fair value of units vested | $ 6,815 |

As of December 31, 2008, there was $7.8 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.5 years.

***(c) Unit Options***

Unit options will have an exercise price that is not less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, its general partner or its general partner's general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior to estimate forfeiture rates . The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant. The Partnership used the simplified method to calculate the expected term.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant. The unit options granted in 2006, 2007 and 2008 generally vest based on 3 years of service (one-third after each year of service). The following weighted average assumptions were used for the Black-Scholes option-pricing model for grants in 2008:

**Crosstex Energy, L.P. Unit Options Granted:** —

| | |
|---|---|
| Weighted average distribution yield | 7.15% |
| Weighted average expected volatility | 30.0% |
| Weighted average risk free interest rate | 1.81% |
| Weighted average expected life | 6 years |
| Weighted average contractual life | 10 years |
| Weighted average of fair value of unit options granted | $ 3.48 |

A summary of the unit option activity for the year ended December 31, 2008 is provided below:

| | Number of Units | Weighted Average Exercise Price |
|---|---|---|
| Outstanding, beginning of period | 1,107,309 | $ 29.65 |
| Granted (b) | 402,185 | 31.58 |
| Exercised | (56,678) | 14.16 |
| Forfeited | (90,208) | 31.29 |
| Expired | (58,414) | 32.93 |
| Outstanding, end of period | 1,304,194 | $ 30.64 |
| Options exercisable at end of period | 540,782 | $ 29.12 |
| Weighted average contractual term (years) end of period: | | |
| Options outstanding | 7.4 | — |
| Options exercisable | 6.5 | — |
| Aggregate intrinsic value end of period (in thousands): | | |
| Options outstanding | $ (a) | — |
| Options exercisable | $ (a) | — |

(a) Exercise price on all outstanding options exceeds current market price.
(b) No options were granted with an exercise price less than market value at grant during 2008.

A summary of the unit options intrinsic value (market value in excess of exercise price at date of exercise) exercised and fair value of units vested (value per Black-Scholes option pricing model at date of grant are provided below (in thousands):

| Crosstex Energy, L.P. Unit Options: | Year Ended December 31, 2008 |
|---|---|
| Intrinsic value of units options | $ 746 |
| exercised Fair value of units vested | $ 279 |

As of December 31, 2008, there was $1.6 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 1.5 years.

**Notes to Consolidated Balance Sheet — (Continued)**

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

The Crosstex Energy, Inc. long-term incentive plan provides for the award of stock options and restricted stock (collectively, "Awards") for up to 4,590,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2008, approximately 626,000 shares remained under the long-term incentive plan for future issuance to participants. A participant may not receive in any calendar year options relating to more than 100,000 shares of common stock. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Shares of common stock underlying Awards that are forfeited, terminated or expire unexercised become immediately available for additional Awards under the long-term incentive plan.

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. CEI's restricted stock granted in 2006, 2007 and 2008 generally cliff vest after three years of service. A summary of the restricted stock activity includes officers and employees of the Partnership and directors of CEI for the year ended December 31, 2008 is provided below:

| Crosstex Energy, Inc. Restricted Shares: | Number of Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Non-vested, beginning of period | 860,275 | $ 21.16 |
| Granted | 361,796 | 32.62 |
| Vested* | (401,004) | 18.41 |
| Forfeited | (63,716) | 21.86 |
| Reduced estimated performance shares | (153,038) | 32.10 |
| Non-vested, end of period | 604,313 | $ 27.62 |
| Aggregate intrinsic value, end of period (in thousands) | $ 2,357 | |

*Vested shares include 116,118 shares withheld for payroll taxes paid on behalf of employees.

The Partnership's executive officers were granted restricted shares during 2008 and 2007, the number of which may increase or decrease based on the accomplishment of certain performance targets based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over a three-year period). The minimum number of restricted shares for all executives of 50,090 and 16,536 for 2008 and 2007, respectively, are included in the non-vested, end of period shares line in the table above. Target performance grants were previously included in the restricted units granted and were included in share-based compensation as it appeared probable that target thresholds would be achieved. However, during the last half of 2008, the Partnership's assets were negatively impacted by hurricanes Gustav and Ike. During this same period the Partnership has also been negatively impacted by the declines in natural gas and NGL prices coupled with the global economic decline and tightening of capital markets. The Partnership expects that its access to capital will be limited due to the lack of liquidity in the capital markets, which will in turn limit its ability to grow until capital for growth is accessible. The impact of these events was significant enough to make the achievement of target performance goals less than probable. Therefore, an expense of $0.7 million previously recorded for target performance-based restricted shares has been retroactively reversed and is shown as a reduction to stock-based compensation expense and a reduction in the number of estimated performance shares outstanding by 153,038 shares in the year ended December 31, 2008. All performance-based awards greater than the minimum performance grant levels will be subject to reevaluation and adjustment until the restricted shares vest. The performance-based restricted shares are included in the current share-based compensation calculations as required by SFAS No. 123(R) when it is deemed probable of achieving the performance criteria.

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 years ended December 31, 2008 are provided below (in thousands):

**Crosstex Energy, Inc. Restricted Shares:**

| | Years Ended December 31, 2008 |
|---|---|
| Aggregate intrinsic value of shares vested | $ 13,493 |
| Fair value of shares vested | $ 7,382 |

As of December 31, 2008, there was $7.2 million of unrecognized compensation costs related to CEI restricted shares for officers and employees. The cost is expected to be recognized over a weighted average period of 2.4 years.

***CEI Stock Options***

No CEI stock options were granted to any officers or employees of the Partnership during 2008.

A summary of the stock option activity includes officers and employees of the Partnership and directors of CEI for the years ended December 31, 2008 is provided below:

| | Number of Shares | Weighted Average Exercise Price |
|---|---|---|
| Outstanding, beginning of period | 105,000 | $ 8.45 |

| | Number of Shares | Weighted Average Exercise Price |
|---|---|---|
| Granted | — | — |
| Cancelled | — | — |
| Exercised | (37,500) | 6.50 |
| Forfeited | — | — |
| Outstanding, end of period | 67,500 | $ 9.54 |
| Options exercisable at end of period | 22,500 | $ 11.05 |

The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of December 31, 2008:

| | |
|---|---|
| Outstanding stock options (15,000 exercisable) (post stock split) | 30,000 |
| Weighted average exercise price (post stock split) | $ 13.33 |
| Aggregate intrinsic value | $ — |
| Weighted average remaining contractual term | 5.9 years |

A summary of the share options intrinsic value (market value in excess of exercise price at date of exercise) exercised and fair value of units vested (value per Black-Scholes option pricing model at date of grant) during the years ended December 31, 2008 is provided below (in thousands):

**Crosstex Energy, Inc. Stock Options:** —

| | |
|---|---|
| Intrinsic value of units options exercised | $ 1,089 |
| Fair value of units vested | $ 38 |

No stock options were granted, cancelled, exercised or forfeited by officers and employees of the Partnership during the years ended December 31, 2008.

As of December 31, 2008, there was $15,449 of unrecognized compensation costs related to non-vested CEI stock options. The cost is expected to be recognized over a weighted average period of 0.8 years.

**(7) 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 as of December 31, 2008 (in thousands):

| | Carrying Value | Fair Value |
|---|---|---|
| Cash and cash equivalents | $ 1,636 | $ 1,636 |
| Trade accounts receivable and accrued revenues | 341,853 | 341,853 |
| Fair value of derivative assets | 31,794 | 31,794 |
| Note receivable | 375 | 375 |
| Accounts payable, drafts payable and accrued gas purchases | 315,622 | 315,622 |
| Current portion of long-term debt | 9,412 | 9,412 |
| Long-term debt | 1,254,294 | 1,148,939 |
| Fair value of derivative liabilities | 51,281 | 51,281 |

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 carrying value for the note receivable approximates the fair value because this note earns interest based on the current prime rate.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $784.0 million as of December 31, 2008 that accrues interest under a floating interest rate structure. Accordingly, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2008, the Partnership also had

borrowings totaling $479.7 million under senior secured notes with a weighted average interest rate of 7.25%. The fair value of these borrowings as of December 31, 2008 was adjusted to reflect current market interest rate for such borrowings as of December 31, 2008.

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.

**(8) Derivatives**

***Interest Rate Swaps***

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk.

The Partnership has entered into eight interest rate swaps as of September 2008 as shown below:

| Trade Date | Term | From | To | Rate | Notional Amounts (in thousands) |
|---|---|---|---|---|---|
| November 14, 2006 | 4 years | November 28, 2006 | November 30, 2010 | 4.3800% | $ 50,000 |
| March 13, 2007 | 4 years | March 30, 2007 | March 31, 2011 | 4.3950% | 50,000 |
| July 30, 2007 | 4 years | August 30, 2007 | August 30, 2011 | 4.6850% | 100,000 |
| August 6, 2007 | 4 years | August 30, 2007 | August 31, 2011 | 4.6150% | 50,000 |
| August 9, 2007 | 3 years | November 30, 2007 | November 30, 2010 | 4.4350% | 50,000 |
| August 16, 2007*. | 4 years | October 31, 2007 | October 31, 2011 | 4.4875% | 100,000 |
| September 5, 2007 | 4 years | September 28, 2007 | September 28, 2011 | 4.4900% | 50,000 |
| January 22, 2008. | 1 year | January 31, 2008 | January 31, 2009 | 2.8300% | 100,000 |
| | | | | | $ 550,000 |

*Amended swap is a combination of two swaps that each had a notional amount of $50.0 million with the same original term.

Each swap fixes the three month LIBOR rate, prior to credit margin, at the indicated rates for the specified amounts of related debt outstanding over the term of each swap agreement. In January 2008, the Partnership amended existing swaps with the counterparties in order to reduce the fixed rates and extend the terms of the existing swaps by one year. The Partnership also entered into one new swap in January 2008.

The Partnership had previously elected to designate all interest rate swaps (except the November 2006 swap) as cash flow hedges for FAS 133 accounting treatment. Accordingly, unrealized gains and losses relating to the designated interest rate swaps were recorded in accumulated other comprehensive income. Immediately prior to the January 2008 amendments, these swaps were de-designated as cash flow hedges. The unrealized loss in accumulated other comprehensive income of $17.0 million at the de-designation dates is being reclassified to earnings over the remaining original terms of the swaps using the effective interest method. The related loss reclassified to earnings and included in (gain) loss on derivatives during the year ended December 31, 2008 is $6.4 million.

The Partnership elected not to designate any of the amended swaps or the new swap entered into in January 2008 as cash flow hedges for FAS 133 treatment. Accordingly, unrealized gains and losses are recorded through the consolidated statement of operations in (gain) loss on derivatives over the period hedged.

In September 2008, the Partnership entered into four additional interest rate swaps. The effect of the new interest rate swaps was to convert the floating rate portion of the original swaps on $450.0 million (all swaps except the January 22, 2008 swap that expires January 31, 2009) from three month LIBOR to one month LIBOR. The Partnership received a cash settlement in September of $1.4 million which represented the present value of the basis point differential between one month LIBOR and three month LIBOR. The $1.4 million was recorded in the consolidated statement of operations in (gain) loss on derivatives.

The table below aligns the new swap which receives one month LIBOR and pays three month LIBOR with the original interest rate swaps.

| Original Swap Trade Date | New Trade Date | From | To | Notional Amounts (in thousands) |
|---|---|---|---|---|
| March 13, 2007 | September 12, 2008 | September 30, 2008 | March 31, 2011 | $ 50,000 |
| September 5, 2007 | September 12, 2008 | September 30, 2008 | September 28, 2011 | 50,000 |
| August 16, 2007 | September 12, 2008 | October 30, 2008 | October 31, 2011 | 100,000 |
| November 14, 2006 | September 12, 2008 | November 28, 2008 | November 30, 2010 | 50,000 |
| August 9, 2007 | September 12, 2008 | November 28, 2008 | November 30, 2010 | 50,000 |
| July 30, 2007 | September 12, 2008 | November 28, 2008 | August 30, 2011 | 100,000 |
| August 6, 2007 | September 23, 2008 | November 28, 2008 | August 30, 2011 | 50,000 |
| | | | | $ 450,000 |

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

| | December 31, 2008 |
|---|---|
| Fair value of derivative assets — current | $ 149 |
| Fair value of derivative assets — long-term | — |
| Fair value of derivative liabilities — current | (17,217) |
| Fair value of derivative liabilities — long-term | (18,391) |
| Net fair value of interest rate swaps | $ (35,459) |

***Commodity Swaps***

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

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

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

| | December 31, 2008 |
|---|---|
| Fair value of derivative assets — current | $ 27,017 |
| Fair value of derivative assets — long term | 4,628 |
| Fair value of derivative liabilities — current | (11,289) |
| Fair value of derivative liabilities — long term | (4,384) |
| Net fair value of commodity swaps | $ 15,972 |

Set forth below is the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at December 31, 2008 (all gas volumes are expressed in MMBtu’s and liquids are expressed in gallons). The remaining terms of the contracts extend no later than June 2010 for derivatives except for certain basis swaps that extend to March 2012. The Partnership’s counterparties to derivative contracts include BP Corporation, Total Gas & Power, Fortis, UBS Energy, Morgan Stanley, J. Aron & Co., a subsidiary of Goldman Sachs and Sempra Energy. 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 | December 31, 2008 | |
|---|---|---|
| | Volume | Fair Value |
| | (In thousands) | |
| *Cash Flow Hedges:* | | |
| Natural gas swaps (short contracts) (MMBtu's) | (600) | $ 1,136 |
| Liquids swaps (short contracts) (gallons) | (16,026) | 12,578 |
| Total swaps designated as cash flow hedges | | $ 13,714 |
| *Mark to Market Derivatives:** Swing swaps (long contracts) | 2,155 | $ 10 |
| Physical offsets to swing swap transactions (short contracts) | (2,155) | — |
| Swing swaps (short contracts) | (397) | (3) |
| Physical offsets to swing swap transactions (long contracts) | 397 | — |
| Basis swaps (long contracts) | 82,681 | 7,464 |
| Physical offsets to basis swap transactions (short contracts) | (1,550) | 9,072 |
| Basis swaps (short contracts) | (78,025) | (6,175) |
| Physical offsets to basis swap transactions (long contracts) | 1,771 | (9,067) |
| Third-party on-system financial swaps (long contracts) | 2,300 | (8,065) |
| Physical offsets to third-party on-system transactions (short contracts) | (2,283) | 8,157 |
| Third-party on-system financial swaps (short contracts) | (172) | 2 |
| Physical offsets to third-party on-system transactions (long contracts) | 155 | 89 |
| Storage swap transactions (long contracts) | 158 | (23) |
| Storage swap transactions (short contracts) | (353) | 797 |
| Total mark to market derivatives | | $ 2,258 |

*All are gas contracts, volume in MMBtu's

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

***Impact of Cash Flow Hedges***

*Natural Gas*

As of December 31, 2008 an unrealized derivative fair value net gain of $1.1 million related to cash flow hedges of gas price risk was recorded in accumulated other comprehensive income (loss). Of this net amount, a $1.1 million gain is expected to be reclassified into earnings through December 2009. The actual reclassification to earnings will be based on mark to market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

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

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

| | Maturity Periods | | | |
|---|---|---|---|---|
| | Less Than One Year | One to Two Years | More Than Two Years | Total Fair Value |
| December 31, 2008 | $ 2,014 | $ 181 | $ 63 | $ 2,258 |

**(9) Fair Value Measurements**

In September 2006, the FASB issued SFAS No. 157, *"Fair Value Measurements"* (SFAS 157). SFAS 157 introduces a framework for measuring fair value and expands required disclosure about fair value measurements of assets and liabilities. SFAS 157 for financial assets and liabilities is effective for fiscal years beginning after November 15, 2007. The Partnership has adopted the standard for those assets and liabilities as of January 1, 2008 and the impact of adoption was not significant.

Fair value 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.

SFAS 157 establishes 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 swaps and interest rate swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. The Partnership determines the value of interest rate swap contracts by utilizing inputs and quotes from the counterparties to these contracts. The reasonableness of these inputs and quotes is verified by comparing similar inputs and quotes from other counterparties as of each date for which financial statements are prepared.

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

| | Total | Level 1 | Level 2 | Level 3 |
|---|---|---|---|---|
| Interest rate swaps | $ (35,459) | — | $ (35,459) | — |
| Commodity swaps | 15,972 | — | 15,972 | — |
| Total | $ (19,487) | — | $ (19,487) | — |

**(10) Commitments and Contingencies**

***(a) Leases — Lessee***

The Partnership has operating leases for office space, office and field equipment and the Eunice plant. The Eunice plant operating lease acquired with the south Louisiana processing assets provides for annual lease payments of $12.2 million with a lease term extending to November 2012. At the end of the lease term we have the option to purchase the plant for $66.3 million or to renew the lease for up to an additional 9.5 years at 50% of the lease payments under the current lease.

The following table summarizes our remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in millions):

| | |
|---|---|
| 2009 | $ 28.4 |
| 2010 | 19.0 |
| 2011 | 17.9 |
| 2012 | 16.4 |
| 2013 | 3.1 |
| Thereafter | 3.7 |
| | $ 88.5 |

***(b) Leases — Lessor***

During 2008, the Partnership leased approximately 162 of its treating plants, most of which the Partnership operates, and 33 of its dew point control plants to customers under operating leases. The initial terms on these leases are generally 12 months, at which time the leases revert to 30-day cancelable leases. As of December 31, 2008, the Partnership only had 31 treating plants under 36 operating leases with remaining non-cancelable lease terms in excess of one year. The future minimum lease rentals are $16.3 million and $5.4 million for the years ended December 31, 2009 and 2010, respectively. These leased treating plants have a cost of $25.4 million and accumulated depreciation of $4.9 million as of December 31, 2008.

***(c) Employment Agreements***

Certain members of management of the Partnership are parties to employment contacts with the general partner. The employment agreements provide those senior managers with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

***(d) Environmental Issues***

The Partnership acquired the South Louisiana Processing Assets from the El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has an active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the oversight of the Louisiana Department of Environmental Quality (LDEQ) and is being conducted under the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that is expected to significantly reduce the cost of and timing for remediation projects. As of December 31, 2007, we had incurred approximately $0.5 million in remediation costs. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, projected costs were accrued as part of the purchase price.

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

The Partnership acquired assets from Duke Energy Field Services, or DEFS, in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of the Conroe site. Moreover, a third-party company has assumed the remediation costs associated with the Conroe site. Therefore, the Partnership does not expect to incur any material environmental liability associated with the Conroe site; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations.

***(e) 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.

On November 15, 2007, Crosstex CCNG Processing Ltd. ("Crosstex Processing"), the Partnership's wholly-owned subsidiary, received a demand letter from Denbury Onshore, LLC ("Denbury"), asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. On April 15, 2008, the parties mediated the matter unsuccessfully. On December 4, 2008, Denbury initiated formal arbitration proceedings against Crosstex Processing, Crosstex Energy Services, L.P., Crosstex North Texas Gathering, L.P., and Crosstex Gulf Coast Marketing, Ltd., seeking $11.4 million and additional unspecified damages. On December 23, 2008, Crosstex Processing filed an answer denying Denbury's allegations and a counterclaim seeking a

declaratory judgment that its processing plant is uneconomic under the Processing Contract. Crosstex Energy, Crosstex Marketing, and Crosstex Gathering also filed an answer denying Denbury's allegations and asserting that they are improper parties as Denbury's claim is for breach of the Processing Contract and none of these entities is a party to that agreement. Crosstex Gathering also filed a counterclaim seeking approximately $40.0 million in damages for the value of the NGLs it is entitled to under its Gas Gathering Agreement with Denbury. Once the three-person arbitration panel has been named and cleared conflicts, the arbitration panel will hold a preliminary conference with the parties to set a date for the final hearing and other case deadlines and to establish discovery limits. Although it is not possible to predict with certainty the ultimate outcome of this matter, the Partnership does not believe this will have a material adverse effect on its consolidated results of operations or financial position.

The Partnership (or its subsidiaries) is defending eleven lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems in north Texas. 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. At this time, five cases are set for trial in 2009. The remaining cases have not yet been set for trial. Discovery is underway. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed the Partnership approximately $6.2 million, including approximately $3.9 million for June 2008 sales and approximately $2.2 million for July 2008 sales. The Partnership believes the July sales of $2.2 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to Crosstex for an administrative claim in the amount of $2.2 but the allowance of the administrative claim status is still subject to approval of the bankruptcy court in accordance with the administrative claim allowance procedures order in the case. The Partnership evaluated these receivables for collectibility and provided a valuation allowance of $3.1 million during the year ended December 31, 2008.

**(11) Segment Information**

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the south Louisiana processing and liquids assets, the processing and transmission assets located in north and south Texas, the pipelines and processing plants located in Louisiana, the Mississippi System, the Arkoma system in Oklahoma and various other small systems. Also included in the Midstream division are the Partnership's energy trading operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or through fixed monthly payments.

The accounting policies of the operating segments are the same as those described in note 2 of the Notes to Consolidated Financial Statements. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt financing costs.

The identifiable assets by segment as of December 31, 2008 are as follows (in thousands):

| | |
|---|---|
| Midstream | $ 2,303,679 |
| Treating | 200,114 |
| Corporate | 29,473 |
| Total | $ 2,533,266 |

**(12) Condensed Consolidating Information**

The following table presents the condensed consolidating balance sheet data for the General Partner and CELP as of December 31, 2008 (in thousands):

**CROSSTEX ENERGY GP, L.P.**

**Notes to Consolidated Balance Sheet — (Continued)**

| | General Partner | CELP | Consolidation Entries | Consolidated |
|---|---|---|---|---|
| Current assets | $ — | $ 391,921 | $ — | $ 391,921 |
| Property, plant and equipment, net | — | 1,527,280 | — | 1,527,280 |
| Fair value of derivative assets | — | 4,628 | — | 4,628 |
| Intangible assets, net | — | 578,096 | — | 578,096 |
| Goodwill | — | 19,673 | — | 19,673 |
| Investment in CELP | 16,805 | — | (16,805) | — |
| Other assets, net | — | 11,668 | — | 11,668 |
| Total assets | $ 16,805 | $2,533,266 | $ (16,805) | $ 2,533,266 |
| Current liabilities | $ — | $ 424,831 | $ — | $ 424,831 |
| Long-term debt | — | 1,254,294 | — | 1,254,294 |
| Other long-term liabilities | — | 24,708 | — | 24,708 |
| Deferred tax liability | — | 8,727 | — | 8,727 |
| Minority interest | — | 3,510 | 777,616 | 781,126 |
| Fair value of derivative liabilities | — | 22,775 | — | 22,775 |
| Partners' equity | 16,805 | 794,421 | (794,421) | 16,805 |
| Total liabilities and partners' equity | $ 16,805 | $2,533,266 | $ (16,805) | $ 2,533,266 |

**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 hereunto duly authorized.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, L.P., its General Partner

By: Crosstex Energy GP, LLC, its General Partner

By: /s/ William W. Davis

William W. Davis
Executive Vice President and
Chief Financial Officer

Date: March 2, 2009