FORM 10-K

CROSSTEX ENERGY INC - XTXI

Filed: March 02, 2009 (period: December 31, 2008)

Annual report which provides a comprehensive overview of the company for the past year

Table of Contents

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: 000-50536

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

Delaware	**52-2235832**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
2501 CEDAR SPRINGS DALLAS, TEXAS	**75201**
(Address of principal executive offices)	*(Zip Code)*

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Exchange on Which Registered
Common Stock, Par Value $0.01 Per Share	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 Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a 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 voting and non-voting common equity held by non-affiliates of the registrant was approximately $803,616,085 on June 30, 2008, based on $34.66 per share, the closing price of the Common Stock as reported on the NASDAQ Global Select Market on such date.

At February 16, 2009, there were 46,420,305 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Registrant's Proxy Statement relating to its 2009 Annual Stockholders' Meeting to be filed with the Securities and Exchange Commission are incorporated by reference herein into Part III of this Report.

TABLE OF CONTENTS

DESCRIPTION

CROSSTEX ENERGY, INC.

PART I

Item 1. *Business*

General

Crosstex Energy, Inc. is a Delaware corporation, formed in April 2000. We completed our initial public offering in January 2004. Our shares of common stock are listed on the NASDAQ Global Select Market under the symbol "XTXI". 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 "Crosstex Energy, Inc." as well as the terms "our," "we," and "us," or like terms, are sometimes used as references to Crosstex Energy, Inc. and its consolidated subsidiaries. References in this report to "Crosstex Energy, L.P.," the "Partnership," "CELP" or like terms refer to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. together with its consolidated subsidiaries.

CROSSTEX ENERGY, INC.

Our assets consist almost exclusively of partnership interests in Crosstex Energy, L.P., a publicly traded limited partnership engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids, or NGLs. These partnership interests consist of the following:

- 16,414,830 common units representing an aggregate 34.0% limited partner interest in the Partnership; and
- 100% ownership interest in Crosstex Energy GP, L.P., the general partner of the Partnership, which owns a 2.0% general partner interest and all of the incentive distribution rights in the Partnership.

Our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. The Partnership is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership's business or to provide for future distributions.

The incentive distribution rights entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

Quarterly distributions by the Partnership steadily increased from the first distribution of $0.25 per unit for the quarter ended March 31, 2003 to $0.63 per unit for the quarter ended June 30, 2008. However, the distribution for third quarter of 2008 operating results was reduced to $0.50 per unit followed by a further reduction to $0.25 per unit for the fourth quarter of 2008 (paid in February 2009). The Partnership's distributions were reduced during the last half of 2008 as a result of a decline in its cash flows from operations due to declines in natural gas and NGL prices during the last half of 2008, gross margin losses due to hurricanes Ike and Gustav and the declines in the global financial markets and economic conditions as discussed under "Crosstex Energy, L.P. — Recent Developments" and "Crosstex Energy, L.P. — Business Strategies."

In response to the recent developments, the Partnership has adjusted its business strategy for 2009 to focus on maximizing liquidity, maintaining a stable asset base, improving the profitability of its assets by increasing their utilization while controlling costs and reducing capital expenditures as discussed under "Crosstex Energy, L.P. — Business Strategies." One of the strategies included amending the Partnership's bank credit facility and its senior note agreements to negotiate terms with its creditors that will allow continued operation of its assets during the current difficult economic conditions. The amended terms of the credit facility and senior secured note agreement prohibit the Partnership from making distributions unless its leverage ratio is below certain levels and the PIK notes, as defined below, have been repaid. The Partnership does not expect that it will will meet these conditions in 2009. Since our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own, we do not expect to receive any significant cash flows until the Partnership is able to improve its leverage ratio and begin making distributions again. As of December 31, 2008, we have cash of $14.0 million which we expect to be sufficient to pay our expenses and federal income taxes over the next several years based on our forecasted cash flows. We do not anticipate making any future dividend payments after the dividend payment in February 2009 with respect to fourth quarter 2008 operating results until we begin receiving distributions from the Partnership again.

Historically we have paid dividends to our stockholders on a quarterly basis equal to the cash we receive from our Partnership distributions, less reserves for expenses, future dividends and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner’s 2.0% general partner interest; and
- cash reserves our board of directors believed were prudent to maintain.

Our ability to pay dividends is limited by the Delaware General Corporation Law, which provides that a corporation may only pay dividends out of existing “surplus,” which is defined as the amount by which a corporation’s net assets exceeds its stated capital. While our ownership of the general partner and the common units of the Partnership are included in our calculation of net assets, the value of these assets may decline to a level where we have no “surplus,” thus prohibiting us from paying dividends under Delaware law.

So long as we own the Partnership’s general partner, under the terms of an omnibus agreement with the Partnership we are prohibited from engaging in the business of gathering, transmitting, treating, processing, storing and marketing natural gas and transporting, fractionating, storing and marketing NGLs, except to the extent that the Partnership, with the concurrence of a majority of its independent directors comprising its conflicts committee, elects not to engage in a particular acquisition or expansion opportunity. The Partnership may elect to forego an opportunity for several reasons, including:

- the nature of some or all of the target’s assets or income might affect the Partnership’s ability to be taxed as a partnership for federal income tax purposes;
- the board of directors of Crosstex Energy GP, LLC, the general partner of the general partner of the Partnership, may conclude that some or all of the target assets are not a good strategic opportunity for the Partnership; or
- the seller may desire equity, rather than cash, as consideration or may not want to accept the Partnership’s units as consideration.

We have no present intention of engaging in additional operations or pursuing the types of opportunities that we are permitted to pursue under the omnibus agreement, although we may decide to pursue them in the future, either alone or in combination with the Partnership. In the event that we pursue the types of opportunities that we are permitted to pursue under the omnibus agreement, our board of directors, in its sole discretion, may retain all, or a portion of, the cash distributions we receive on our partnership interests in the Partnership to finance all, or a portion of, such transactions, which may reduce or eliminate dividends paid to our stockholders.

CROSSTEX ENERGY, L.P.

Crosstex Energy, L.P., is an independent midstream energy company engaged in the gathering, transmission, treating, processing and marketing of natural gas and NGLs. It connects the wells of natural gas producers in its market areas to its gathering systems, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of NGLs, fractionates NGLs into purity products and markets those products for a fee, transports natural gas and ultimately provides natural gas to a variety of markets. It purchases natural gas from natural gas producers and other supply points and sells that natural gas to utilities, industrial consumers, other marketers and pipelines. It operates processing plants that process gas transported to the plants by major interstate pipelines or from its own gathering systems under a variety of fee arrangements. In addition, it purchases natural gas from producers not connected to its gathering systems for resale and sells natural gas on behalf of producers for a fee.

The Partnership has two operating segments, Midstream and Treating. The Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, while the Treating division focuses on the removal of impurities from natural gas to meet pipeline quality specifications. The primary Midstream assets include over 5,700 miles of natural gas gathering and transmission pipelines, 12 natural gas processing plants and four fractionators. The 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. The transmission pipelines primarily receive natural gas from the Partnership's gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. The processing plants remove NGLs from a natural gas stream and the Partnership's fractionators separate the NGLs into separate NGL products, including ethane, propane, iso- and normal butanes and natural gasoline. The primary Treating assets include approximately 225 natural gas amine-treating plants and 56 dew point control plants. The Partnership's 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 18 to the consolidated financial statements for financial information about these operating segments.

Set forth in the table below is a list of the Partnership's significant 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

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 the Partnership's 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"), such as our investment in CELP, 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, the Partnership's 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 the Partnership's gross margin for the fourth quarter of 2008 and could continue to negatively impact our gross margin (revenue less cost of gas purchased) in 2009. A significant percentage of inlet gas at its 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, the Partnership is not responsible for the fuel or shrink associated with processing. Under margin contracts the Partnership realizes 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 the Partnership has seen some improvement in NGL prices and the fractionation spread in the early months of 2009 over the levels experienced in December 2008, the Partnership believes that its 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 the Partnership's gross margin was attributable to gas processing as compared to 46.1% of its 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 the contractual processing arrangements used by the Partnership.

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 the 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 the Partnership's 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. The Partnership believes 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 its pipeline and gathering systems and processed through its processing plants. The Partnership has seen a decline in drilling activity by gas producers in its 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 the Partnership's customers, including one of its largest customers in the Barnett Shale, have recently announced drilling plans for 2009 that are substantially below their drilling levels during 2008.

The Partnership's business was also negatively impacted by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September 2008. Although the majority of its 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 its 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 the Partnership does not anticipate that gas production to its south Louisiana plants will recover to pre-hurricane levels until mid-2009, when all repairs are expected to be complete. Additionally, one of the Partnership's 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. 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 the Partnership's gross margin of approximately $22.9 million.

Two of the Partnership's 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, the 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 the Partnership was successful in rerouting the gas to its 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, the Partnership's 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, the Partnership adjusted its business strategy in the fourth quarter 2008 and for 2009 to focus on maximizing liquidity, maintaining a stable asset base, improving the profitability of its assets by increasing their utilization while controlling costs and reducing capital expenditures. The Partnership has undertaking the following steps to implement the strategy:

- The Partnership intends to operate its existing asset base to enhance profitability by undertaking initiatives to maximize utilization and by improving operations, reducing operating costs and renegotiating contracts, when appropriate, to improve the economics. The Partnership has 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.
- The Partnership amended its bank credit facility and its senior secured note agreements in November 2008 and again in February 2009 to negotiate terms that facilitate its compliance with debt covenants while it operates its assets during the current difficult economic conditions. The terms of the amended agreements allow the Partnership to maintain a higher level of leverage and to maintain a lower interest coverage ratio;

however, interest costs will increase and the ability to pay distributions and incur additional indebtedness will be restricted when it is 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."

- The Partnership has lowered its 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 the credit facility and senior secured note agreement prohibit the Partnership from making distributions unless its leverage ratio is below certain levels and the PIK notes have been repaid as discussed more fully under "Amendments to Credit Documents". The Partnership does not expect that it will meet these conditions in 2009.
- The Partnership sold certain non-strategic assets in November 2008 and used the proceeds from such sales to reduce its outstanding borrowings under its bank credit facility. The Partnership received $85.0 million for the sale of its 12.4% interest in the Seminole gas processing plant to an unaffiliated third party and it received $20.0 million for the assignment of a transportation contract right to another unaffiliated third party. The Partnership may consider selling other non-strategic assets during 2009 and use the proceeds to further reduce its indebtedness if it is able to obtain attractive offers for such assets.
- The Partnership has reduced 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. The Partnership's ability to grow its asset base through the continued development of its north Texas and Louisiana assets or through acquisitions will be limited due to its lack of access to capital markets and due to restrictions under its debt agreements. The Partnership will use cash flow from operations and existing capacity under its bank credit facility to fund its 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 the bank credit facility.
- The Partnership has reduced general and administrative expenses by reducing its work force by approximately 8.0% through the elimination of open positions and certain corporate positions and minimizing all non-essential costs. It has also reduced 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, the Partnership amended its bank credit facility and the 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 the Partnership 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 the bank credit facility and the senior note agreement by 1.25% per annum and increased the other fees associated with the bank credit facility.

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

Under the amended bank credit facility, if the Partnership is operating at higher leverage ratios, its interest margin over the London Interbank Offering Rate ("LIBOR") on its 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 the LIBOR borrowings will decline from the maximum level of 4.00% to a low of 2.75% when the Partnership 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 the Partnership's 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 the Partnership pays 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 the 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 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 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 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.

Under the Partnership's amended bank credit facility and senior secured note agreement, it 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, 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 amended bank credit facility and senior secured note agreement, the Partnership may not make quarterly distributions to its 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, it 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, it may make quarterly distributions to unitholders 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 Partnership's bank credit facility. Based on the Partnership's forecasted leverage ratios for 2009, it does not anticipate making quarterly distributions in 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 the leverage ratio does not improve and the PIK notes are not first repaid.

The amended credit facility and senior note agreement also limit the Partnership's annual capital expenditures (excluding maintenance capital expenditures) to $120.0 million in 2009 and $75.0 million in 2010 (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 its credit facility and the current condition of the capital markets because, as discussed below, the Partnership may only use a portion of the proceeds from the incurrence of unsecured debt and the issuance of equity to make such acquisitions.

The amended credit facility and senior secured note agreement also require the Partnership 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 its leverage ratio exceeds 4.50 to 1.00. If the 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 the 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 the Partnership's 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.

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

Acquisitions and Expansion in Recent Years

North Texas Assets. The Partnership's 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, the Partnership 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 the Partnership's customers access to premium midwest and east coast markets.

On June 29, 2006, the Partnership expanded its operations in the north Texas area through its 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 it refers to in conjunction with the NTP and its 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. 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 the Partnership's 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, the Partnership began expanding its north Texas pipeline gathering system. The continued expansion of the north Texas gathering systems to handle the growing production in the Barnett Shale was one of the Partnership's 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, the Partnership has connected 444 new wells to its gathering system and significantly increased the dedicated acreage owned by other producers. The Partnership's processing capacity in the Barnett Shale is 280 MMcf/d including the Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, the Azle plant, which is a 50 MMcf/d cryogenic processing plant and the Goforth plant, which is a 30 MMcf/d processing plant. In 2007 and 2008, the Partnership constructed a 29-mile expansion in north Johnson County to its 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 increase to approximately 400 MMcf/d in April 2009 by the addition of compression. The Partnership has 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 the north Texas gathering system was approximately 1,100 MMcf/d and total throughput on the 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, the Partnership commenced construction of an $80.0 million natural gas processing facility called Bear Creek in Hood County near its 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, the Partnership does not anticipate that the additional processing capacity provided by the Bear Creek plant will be needed until late 2010 or in 2011. Therefore, it has decided to put this construction project on hold until the demand for this processing capacity returns, at which time it will seek to obtain financing for this project. As of December 31, 2008, the Partnership has 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.

The Partnership has budgeted approximately $57.0 million for continued development of its 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 its gathering systems in north Texas. Several of the Partnership's customers, including one of its 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 capital expenditures related to well connections during 2009 may be less than budgeted.

North Louisiana Expansion Project. In April 2007, the Partnership completed construction and commenced operations on its north Louisiana expansion, which is an extension of its 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 the Red River lateral. The 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 the Partnership 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.

The Partnership has 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. The Partnership has 10 year firm transportation contracts subscribing to all the capacity on this project with four large producers.

Other Developments

Partnership's Issuance of Common Units. On April 9, 2008, the Partnership 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 our 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 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. We own all 4,668,000 of the units that converted.

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

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. The senior subordinated series D units will convert to common units representing limited partner interests of the Partnership on March 23, 2009. Since the Partnership 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. We do not own any of the senior subordinated series D units.

Midstream Segment

Gathering, Processing and Transmission. The Partnership's primary Midstream assets include its 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 gross margin in 2008 and 2007.

- *North Texas Assets.* On June 29, 2006, the Partnership 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 the Partnership's 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, the Partnership began expanding its north Texas pipeline gathering system.
  - *Gathering System.* Since the date of the acquisition through December 31, 2008, the Partnership has connected 444 new wells to its north Texas gathering system and significantly increased the dedicated acreage owned by other producers. During May and July 2008, the Partnership completed the 29 mile expansion in north Johnson County to its 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 the 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, the Partnership has constructed three gas processing plants with a total processing capacity in the Barnett Shale of 280 MMcf/d including its Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, its Azle plant, which is a 50 MMcf/d cryogenic processing plant and its Goforth plant, which is a 30 MMcf/d processing plant. The Partnership has 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).* The Partnership expanded its 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 the Partnership's customers access to premium midwest and east coast markets.
- *South Texas Assets.* The Partnership has 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.* The Partnership's Louisiana assets include its LIG intrastate pipeline system and its gas processing and liquids business in south Louisiana, referred to as the 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, the 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, the Partnership extended its 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. The 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 the Partnership 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, the Partnership completed a number of operational changes at its Eunice facility and other plants to idle certain equipment, reduce operating expenses and reconfigure operations to manage the lower utilization. In addition, the Partnership has increased its focus on upstream markets and opportunities through integration of the LIG system and south Louisiana processing assets to improve overall performance. In 2008, the 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 the 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. The Partnership anticipates 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 the Cajun Sibon pipeline system to the 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 the Riverside plant 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 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.* The Partnership 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 it became the operator of the plant. The plant has a net capacity to the interest of 186 MMcf/d. For the year ended December 31, 2008, this facility processed approximately 110,000 MMBtu/d net to the Partnerships' 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 the Blue Water plant from the Blue Water offshore system and the plant is not currently in operation. At this time, the Partnership has not found alternative sources of new gas for the Blue Water plant but the Partnership will continue to look for new sources of gas, including the option of moving gas from the Partnership's LIG system over to Blue Water plant. The Partnership does 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 the 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. The Partnership 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 its estimated fair value 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 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.* The Partnership's 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 the 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. The Partnership expanded this gas gathering system in May 2008 and it has a current capacity of 100 MMcf/d. The Partnership is expecting to receive its first delivery of Haynesville Shale gas into its 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.* The Partnership offers natural gas marketing services on behalf of producers of natural gas that is not gathered, transmitted, treated or processed by its assets. They market this gas on a number of interstate and intrastate pipelines. These volumes averaged approximately 85,000 MMBtu/d in 2008.

Treating Segment

The Partnership operates (or leases 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. Its treating division contributed approximately 12.0% of the gross margin in 2008 and 2007. At December 31, 2008, the Partnership 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. The Partnership's Treating division views dew point control as complementary to its treating business.

The Partnership believes it has 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 the Partnerships' 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 the Partnership to operate the treating facilities, it either charges a fixed rate per Mcf of natural gas treated or charges 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. The Partnership believes that its 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.

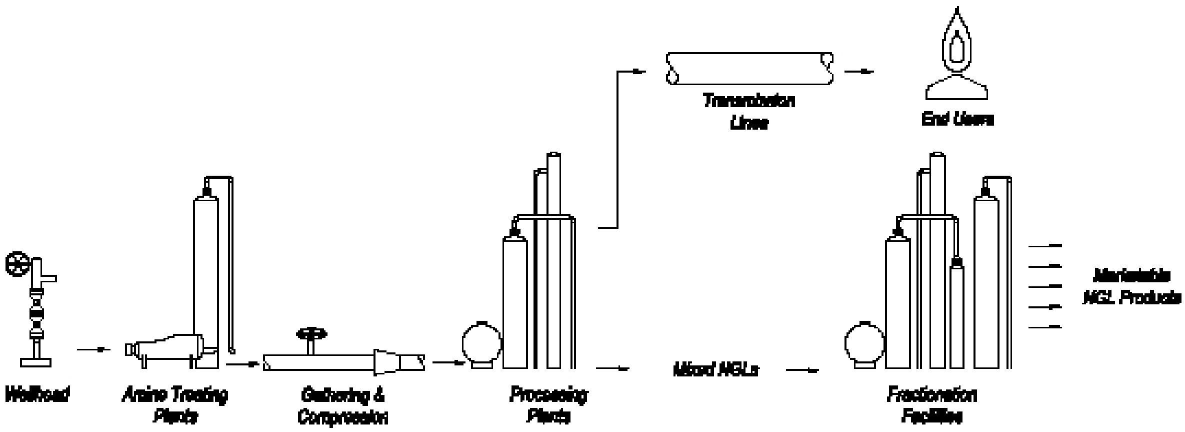
The Partnership's treating growth strategy is to utilize its existing fleet of amine plants to support growth in the Haynesville Shale gas play. The Partnership believes its track record of reliability, current availability of equipment and strategy of sourcing new equipment provide a significant advantage 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, the Partnership sold its 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. CELP acquired its 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 the 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 the Partnership purchases natural gas, it establishes a margin normally by selling natural gas for physical delivery to third-party users. The Partnership can also use over-the-counter derivative instruments or enter into future delivery obligations under futures contracts on the New York Mercantile Exchange. Through these transactions, it seeks to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. The Partnership's 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. The Partnership faces strong competition in obtaining natural gas supplies and in the marketing and transportation of natural gas and NGLs. Its 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 the Partnership's competitors offer more services or have greater financial resources and access to larger natural gas supplies than it does. The Partnership's competition differs in different geographic areas.

The Partnership's 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 it. It also faces competition from vendors of used equipment that occasionally operate plants for producers. In addition, CELP routinely loses business to gas gatherers who have underutilized treating or processing capacity and can take the producers' gas without requiring wellhead treating. The Partnership 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, the Partnership has 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 the Partnership's marketing operations.

The Partnership faces 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 the Partnership's competitors have greater financial resources or lower capital costs, or are willing to accept lower returns or greater risks. The competition differs by region and by the nature of the business or the project involved.

Natural Gas Supply

The Partnership's transmission pipelines have connections with major interstate and intrastate pipelines, which it believes has ample supplies of natural gas in excess of the volumes required for these systems. In connection with the construction and acquisition of its gathering systems, the Partnership evaluated 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 the Partnership's investment. Based on these facts, the Partnership believes that there should be adequate natural gas supply to recoup its investment with an adequate rate of return. The Partnership does not routinely obtain independent evaluations of reserves dedicated to its systems due to the cost and relatively limited benefit of such evaluations. Accordingly, it does not have estimates of total reserves dedicated to the systems or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

The Partnership is diligent in attempting to ensure that it issues credit to only credit-worthy customers. However, the purchase and resale of gas exposes it 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 its overall profitability.

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

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. The Partnership does not own any interstate natural gas pipelines, so the Federal Energy Regulatory Commission, or FERC, does not directly regulate its operations under the National Gas Act, or NGA. However, FERC's regulation of interstate natural gas pipelines influences certain aspects of the Partnership's business and the market for its 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 the Partnership does not own any interstate pipelines, it does transport some gas in interstate commerce. The rates, terms and conditions of service under which the Partnership transports natural gas in its pipeline systems in interstate commerce is 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 the 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 the Partnership's 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 the Louisiana and south Texas pipeline systems are scheduled for March and April 2009, respectively.

Intrastate Pipeline Regulation. The Partnership's 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. The Partnership owns a number of natural gas pipelines that it believes 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.

The Partnership is 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 the Partnership sells natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. Its 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. The Partnership cannot predict the ultimate impact of these regulatory changes on its natural gas marketing operations but does not believe that it will be affected by any such FERC action materially differently than other natural gas marketers with whom it competes.

Environmental Matters

General. The Partnership's 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 its overall costs of doing business, including cost of planning, constructing, and operating plants, pipelines and other facilities. Included in the Partnership's 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 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 the Partnership currently holds all material governmental approvals required to operate its major facilities. As part of the regular overall evaluation of its operations, the Partnership has implemented procedures to review and update governmental approvals as necessary. We believe that the Partnership's 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 its 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 the Partnership's possible future operations, and we cannot assure you that the Partnership 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, the Partnership may be unable to pass on those cost increases to its customers. A discharge of hazardous substances or wastes into the environment could, to the extent losses related to the event are not insured, subject the Partnership 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. The Partnership 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 the Partnership's 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, the Partnership 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, the Partnership 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. The Partnership has not received any notification that it may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state laws.

The Partnership also generates, 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 RCRA, and comparable state statutes. The Partnership is not currently required to comply with a substantial portion of the RCRA requirements because its 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 it 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 the Partnership's capital expenditures or plant operating expenses.

The Partnership currently owns or leases, and has in the past owned or leased, and in the future 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 the Partnership during the operating history of those facilities. In addition, a number of these properties may have been operated by third parties over whom the Partnership 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, RCRA, and analogous state laws. Under these laws, the Partnership could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination, or to take action to prevent future contamination.

The Partnership acquired the 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. The Partnership has completed the remediation work on this site pending the final review and approval of reports by LDEQ. As of December 31, 2008, the Partnership 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 the Partnership's ownership, these costs were accrued as part of the purchase price.

The Partnership 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 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. This remediation work is nearing completion. The Partnership does not expect to incur any material liability in connection with the remediation 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.

The Partnership 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. The Partnership does not expect to incur any material liability in connection with the remediation 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. The Partnership's 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 the Partnership's facilities, and impose various monitoring and reporting requirements. Pursuant to these laws and regulations, the Partnership 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. The

Partnership 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 the Partnership's financial condition or operating results, and the requirements are not expected to be more burdensome to the Partnership 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 the Partnership conducts business could adversely affect the demand for the products it stores, transports and processes, and depending on the particular program adopted could increase the costs of its operations, including costs to operate and maintain its facilities, install new emission controls on its facilities, acquire allowances to authorize its greenhouse gas emissions, pay any taxes related to its greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. The Partnership may be unable to recover any such lost revenues or increased costs in the rates it charges its customers, and any such recovery may depend on events beyond its 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 the Partnership's revenues or increases in its expenses as a result of climate control initiatives could have adverse effects on its 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. The Partnership believes that it is 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 its results of operations.

Employee Safety. The Partnership is 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. The Partnership believes that its 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. The Partnership's 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 the Partnership's 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. The Partnership believes that its 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 its 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 the Partnership's south Louisiana operations in Houston, Texas with lease terms expiring in January 2013 and approximately 11,800 square feet of office space for its 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 the Partnership's computer hardware and will continue to be occupied through December 2009.

Employees

As of December 31, 2008, the Partnership (through its subsidiaries) employed approximately 780 full-time employees. Approximately 270 of the employees were general and administrative, engineering, accounting and commercial personnel and the remainders were operational employees. The Partnership is not party to any collective bargaining agreements, and has not had any significant labor disputes in the past. We believe that the Partnership has good relations with its 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 pay dividends to our shareholders and the trading price of our common shares 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.

Our cash flow consists almost exclusively of distributions from Crosstex Energy, L.P.

Our only cash-generating assets are our partnership interests in Crosstex Energy, L.P. Our cash flow is therefore completely dependent upon the ability of the Partnership to make distributions to its partners. The Partnership's bank credit facility and senior secured note agreement contain covenants limiting its ability to make distributions to unitholders so long as it does not meet certain financial ratios and tests. Under the amended bank credit facility and senior secured note agreement, it may not make quarterly distributions to its 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, it may make the minimum quarterly distribution of up to $0.25 unit if the PIK notes have been repaid. If the leverage ratio is less than 4.00 to 1.00, it may make quarterly distributions to unitholders 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. In order to repay the PIK notes prior to their scheduled maturity, the Partnership will need to amend or refinance its bank credit facility.

Based on the amended provisions in the Partnership's credit facility, its current anticipated cash flows for 2009 and current economic conditions, it does not currently expect to be able to pay distributions to its unitholders in 2009 other than the distribution paid in February 2009 related to fourth quarter 2008 operating results. Even if it does not pay a distribution to unitholders, its unitholders, including us, may be liable for taxes on their share of the Partnership's taxable income. We do not anticipate making any future dividend payments after the dividend payment in February 2009 with respect to fourth quarter 2008 operating results until we begin receiving distributions from the Partnership again.

In addition, even if the Partnership's credit documents do not prohibit it from making distributions, the Partnership still may not have sufficient available cash each quarter to pay distributions to unitholders. The amount of cash that the Partnership can distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas transported in its gathering and transmission pipelines;
- the level of the Partnership's processing and treating operations;
- the fees the Partnership charges and the margins it realizes for its services;
- the price of natural gas;
- the relationship between natural gas and NGL prices;
- its level of operating costs; and
- restrictions on distributions contained in its bank credit facility.

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

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

Because of these factors, even if the Partnership's credit documents do not prohibit it from making distributions, the Partnership 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 the Partnership has available for distribution depends primarily upon its 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, the Partnership may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records net income.

We are largely prohibited from engaging in activities that compete with the Partnership.

So long as we own the general partner of the Partnership, we are prohibited by an omnibus agreement with the Partnership from engaging in the business of gathering, transmitting, treating, processing, storing and marketing natural gas and transporting, fractionating, storing and marketing NGLs, except to the extent that the Partnership, with the concurrence of its independent directors comprising its conflicts committee, elects not to engage in a particular acquisition or expansion opportunity. This exception for competitive activities is relatively limited. Although we have no current intention of pursuing the types of opportunities that we are permitted to pursue under the omnibus agreement such as competitive opportunities that the Partnership declines to pursue or permitted activities that are not competition with the Partnership, the provisions of the omnibus agreement may, in the future, limit activities that we would otherwise pursue.

In our corporate charter, we have renounced business opportunities that may be pursued by the Partnership or by certain stockholders.

In our restated charter and in accordance with Delaware law, we have renounced any interest or expectancy we may have in, or being offered an opportunity to participate in, any business opportunities, including any opportunities within those classes of opportunity currently pursued by the Partnership, presented to:

- persons who are officers or directors of the company or who, on October 1, 2003, were, and at the time of presentation are, stockholders of the company (or to persons who are affiliates or associates of such officers, directors or stockholders), if the company is prohibited from participating in such opportunities by the omnibus agreement; or
- any investment fund sponsored or managed by Yorktown Partners LLC, including any fund still to be formed, or to any of our directors who is an affiliate or designate of these entities.

As a result of this renunciation, these officers, directors and stockholders should not be deemed to be breaching any fiduciary duty to us if they or their affiliates or associates pursue opportunities presented as described above.

Although we control the Partnership, the general partner owes fiduciary duties to the Partnership and the unitholders.

Conflicts of interest exist and may arise in the future as a result of the relationship between us and our affiliates, including the general partner, on the one hand, and the Partnership and its limited partners, on the other hand. The directors and officers of Crosstex Energy GP, LLC have fiduciary duties to manage the general partner in a manner beneficial to us, its owner. At the same time, the general partner has a fiduciary duty to manage the Partnership in a manner beneficial to the Partnership and its limited partners. The board of directors of Crosstex Energy GP, LLC will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest or that of our stockholders.

For example, conflicts of interest may arise in the following situations:

- the allocation of shared overhead expenses to the Partnership and us;
- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and the Partnership, on the other hand, including obligations under the omnibus agreement;
- the determination of the amount of cash to be distributed to the Partnership's partners and the amount of cash to be reserved for the future conduct of the Partnership's business;
- the determination whether to make borrowings under the capital facility to pay distributions to partners; and
- any decision we make in the future to engage in activities in competition with the Partnership as permitted under our omnibus agreement with the Partnership.

If the general partner is not fully reimbursed or indemnified for obligations and liabilities it incurs in managing the business and affairs of the Partnership, its value, and therefore the value of our common stock, could decline.

The general partner may make expenditures on behalf of the Partnership for which it will seek reimbursement from the Partnership. In addition, under Delaware partnership law, the general partner, in its capacity as the general partner of the Partnership, 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 the general partner. To the extent the general partner incurs obligations on behalf of the Partnership, it is entitled to be reimbursed or indemnified by the general partner. In the event that the Partnership is unable or unwilling to reimburse or indemnify the general partner, the general partner may be unable to satisfy these liabilities or obligations, which would reduce its value and therefore the value of our common stock.

The Partnership 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 the Partnership from meeting its 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 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 or to the Partnership on acceptable terms or at all. If funding is not available when needed, or is available only on unfavorable terms, we and the Partnership may be unable to meet our obligations as they come due. Moreover, without adequate funding, the Partnership may be unable to execute its 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 revenues and results of operations. Further, the Partnership's customers may increase collateral requirements or reduce the business the customers transact with the Partnership to reduce credit exposure.

Due to current economic conditions, the Partnership's ability to obtain funding under its bank credit facility could be impaired.

The Partnership operates in a capital-intensive industry and relies on its bank credit facility to finance a significant portion of its capital expenditures. Its ability to borrow under the 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, the Partnership may be unable to obtain adequate funding under its bank credit facility because:

- one or more of its 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 bank credit facility, 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, the Partnership entered into an amendment to its 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 the Partnership will be able to comply with any newly-negotiated covenants in the future or that it will be able to obtain waivers or amendments of these covenants in the event of future noncompliance. If the Partnership is not in compliance with these covenants, and if it is unable to secure necessary waivers or other amendments from the counterparties, it will not have access to the bank credit facility, which could significantly affect its ability to meet expenses and operate its business. Further, such noncompliance could cause a default under the bank credit facility, which could result in acceleration of the Partnership's outstanding debt.

If the Partnership is unable to access funds under its bank credit facility, it will need to meet capital requirements, including some of its 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 operations or the funds the Partnership is able to obtain under its bank credit facility or other sources of liquidity are not sufficient to meet capital requirements, then the Partnership may need to delay or abandon capital projects or other business opportunities, which could have a material adverse effect on its results of operations and financial condition. Furthermore, if the current pressures on credit continue or worsen, the Partnership may not be able to refinance its then-outstanding debt or replace its then-outstanding letters of credit when due, which could have a material adverse effect on its business.

The Partnership's profitability is dependent upon prices and market demand for natural gas and NGLs, which are beyond its control and have been volatile.

The Partnership's business is subject to significant risks due to fluctuations in commodity prices. Its exposure to these risks is primarily in the gas processing component of its business. A large percentage of the processing fees are realized under percent of liquids (POL) contracts that are directly impacted by the market price of NGLs. It also realizes 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 the Partnership's 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 the Partnership is 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 the Partnership's gross margin from processing. The Partnership has a number of margin contracts on its Plaquemine and Gibson processing plants that expose it 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 the Partnership's margins, and may negatively impact its gross margin further if such declines continue.

In the past, the prices of natural gas and NGLs have been extremely volatile and the Partnership expects 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 the Partnership's 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.

The Partnership may not be successful in balancing its 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 purchases and sales not to be balanced. If purchases and sales are not balanced, the Partnership will face increased exposure to commodity price risks and could have increased volatility in its operating income.

The markets and prices for residue gas and NGLs depend upon factors beyond the Partnership's 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 the Partnership's profitability by influencing drilling activity and well operations, and thus the volume of gas it can gather and process. This volatility may cause the Partnership gross margin and cash flows to vary widely from period to period. Hedging strategies may not be sufficient to offset price volatility risk and, in any event, do not cover all of the Partnership throughput volumes. Moreover, hedges are subject to inherent risks, which we describe in "— The Partnership's use of derivative financial instruments does not eliminate its exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reduced income." For a discussion of our risk management activities, please read Item 7A, "Quantitative and Qualitative Disclosures about Market Risk."

Due to the Partnership's lack of asset diversification, adverse developments in its gathering, transmission, treating, processing and producer services businesses would materially impact its financial condition.

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

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

Many of the Partnership's 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 its 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 the Partnership's pipeline and gathering systems and processing through its processing plants. The Partnership has seen a decline in drilling activity by gas producers in its 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 its customers, including one of its 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 the Partnership operations.

The Partnership is exposed to the credit risk of its customers and counterparties, and a general increase in the nonpayment and nonperformance by those customers could have an adverse effect on financial condition and results of operations.

Risks of nonpayment and nonperformance by the Partnership's customers are a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by its customers could adversely affect the results of operations and reduce the Partnership's ability to make distributions to its unitholders. Many of the Partnership's 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 the Partnership's 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 customers' liquidity and ability to make payment or perform on their obligations to the Partnership. Furthermore, some of the 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 the Partnership.

The Partnership's use of derivative financial instruments does not eliminate exposure to fluctuations in commodity prices and interest rates and has in the past and could in the future result in financial losses or reductions in income.

The Partnership's operations expose it to fluctuations in commodity prices, and its bank credit facility exposes the Partnership to fluctuations in interest rates. The Partnership uses 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 its exposure to short-term volatility in commodity prices and interest rates. The Partnership has hedged only portions of its variable-rate debt and expected natural gas supply, NGL production and natural gas requirements. It continues to have direct interest rate and commodity price risk with respect to the unhedged portions. In addition, to the extent the Partnership hedges commodity price and interest rate risks using swap instruments, it will forego the benefits of favorable changes in commodity prices or interest rates.

Even though monitored by management, the Partnership's hedging activities may fail to protect it and could reduce earnings and cash flow. Its 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;
- the Partnership's 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 the Partnership seeks protection. For example:
- the duration of a hedge may not match the duration of the risk against which it seeks protection;
- variations in the index used to price a commodity hedge may not adequately correlate with variations in the index used to sell the physical commodity (known as basis risk); and
- the Partnership may not produce or process sufficient volumes to cover swap arrangements entered into for a given period. If its actual volumes are lower than the volumes it estimated when entering into a swap for the period, the Partnership might be forced to satisfy all or a portion of its derivative obligation without the benefit of cash flow from its sale or purchase of the underlying physical commodity, which could adversely affect liquidity.

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

The Partnership must continually compete for natural gas supplies, and any decrease in its supplies of natural gas could adversely affect its financial condition and results of operations.

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

In order to maintain or increase throughput levels in the Partnership's natural gas gathering systems and asset utilization rates at the Partnership's treating and processing plants, it must continually contract for new natural gas supplies. The Partnership may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting its ability to connect new wells to its gathering facilities include its success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity near its 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 the Partnership's systems. The Partnership has no control over producers and depends on them to maintain sufficient levels of drilling activity. A material decrease in natural gas production or in the level of drilling activity in the Partnership's principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on results of operations and financial position.

The Partnership is vulnerable to operational, regulatory and other risks associated with its assets including, with respect to its south Louisiana and the Gulf of Mexico assets, the effects of adverse weather conditions such as hurricanes.

The Partnership operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because it has a significant portion of its assets located in south Louisiana and the Gulf of Mexico. In the third and fourth quarters of 2008, the Partnership's business was negatively impacted by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September. Although the majority of the Partnership's 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 the Partnership's 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 the Partnership does not anticipate that gas production to its south Louisiana plants will recover to pre-hurricane levels until mid-2009, when all repairs are expected to be complete. Additionally, one of the Partnership's 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. The Partnership's 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 the Partnership's gross margin of approximately $22.9 million in the last half of 2008.

The Partnership's concentration of activity in Louisiana and the Gulf of Mexico makes us more vulnerable than many of its 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 the Partnership's operations could experience the same condition at the same time, these conditions could have a relatively greater impact on its results of operations than they might have on other midstream companies who have operations in more diversified geographic areas.

In addition, the Partnership's 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 the Partnership's financial condition and results of operations.

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

Growing the Partnership's business by constructing new pipelines and processing and treating facilities subjects the Partnership 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 the Partnership intends to grow business is through the construction of additions to 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 the Partnership's expectations. Generally, the Partnership may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, the Partnership may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. The Partnership may also rely on estimates of proved reserves in the 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 the expected investment return, which could adversely affect its results of operations and financial condition. In addition, the Partnership faces the risks of construction delay and additional costs due to obtaining rights-of-way and local permits and complying with city ordinances, particularly as it expands operations into more urban, populated areas such as the Barnett Shale.

Acquisitions typically increase the Partnership's debt and subject it to other substantial risks, which could adversely affect its results of operations.

From time to time, the Partnership may evaluate and seek to acquire assets or businesses that it believes complement existing business and related assets. The Partnership may acquire assets or businesses that it plans 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.

The Partnership's 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 the Partnerships operations and cash flows. If the Partnership consummates any future acquisition, its 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 it will consider in determining the application of these funds and other resources.

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

The Partnership expects to encounter significant competition in any new geographic areas into which it seeks to expand and its ability to enter such markets may be limited.

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

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

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

For the year ended December 31, 2008, approximately 46.0% of Partnership sales of gas which were transported using its 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 the Partnership in the marketing of natural gas it often competes in the end-user and utilities markets primarily on the basis of price. The inability of management to renew or replace current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on profitability.

The Partnership depends on certain key customers, and the loss of any of those key customers could adversely affect financial results.

The Partnership derives a significant portion of its revenues from contracts with key customers. To the extent that these and other customers may reduce volumes of natural gas purchased under existing contracts, the Partnership would be adversely affected unless it were able to make comparably profitable arrangements with other customers. Several of the Partnership's customers, including one of its 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.

The Partnership's business involves many hazards and operational risks, some of which may not be fully covered by insurance.

The Partnership's 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 Partnership related operations. The Partnership's 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 its operations. The Partnership is not fully insured against all risks incident to its business. In accordance with typical industry practice, the Partnership does not have any property insurance on any of its underground pipeline systems that would cover damage to the pipelines. It is not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. The Partnership's business interruption insurance covers only its Gregory processing plant. If a significant accident or event occurs that is not fully insured, it could adversely affect operations and financial condition.

The threat of terrorist attacks has resulted in increased costs, and future war or risk of war may adversely impact the Partnership's results of operations and its 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 Partnership 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 the Partnership's 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 the Partnership to obtain. Its insurance policies now generally exclude acts of terrorism. Such insurance is not available at what management believes to be acceptable pricing levels. A lower level of economic activity could also result in a decline in energy consumption, which could adversely affect revenues or restrict future growth.

Federal, state or local regulatory measures could adversely affect the Partnership's business.

While the FERC generally does not regulate the Partnership's operations, it influences certain aspects of the Partnership's business and the market for its products. The rates, terms and conditions of service under which the Partnership transports natural gas in its pipeline systems in interstate commerce are subject to FERC regulation under the Section 311 of the NGPA. Not only are the Partnerships 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 rates for Section 311 transportation service or intrastate transportation service should be lowered the Partnership's business could be adversely affected.

The Partnership's 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 its 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. The Partnership's 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. The Partnership cannot predict what effect, if any, such changes might have on its 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 the Partnership's business. It is subject to some ratable take and common purchaser statutes in the states where it operates. 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 the Partnership's right as an owner of gathering facilities to decide with whom it will 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 the Partnership operates have adopted complaint-based or other limited economic regulation of natural gas gathering activities. States in which the Partnership operates 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 the Partnership conducts 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 its 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 the Partnership's 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. The Partnership's 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. The Partnership expects the costs for compliance with TRRC and DOT regulations to be approximately \$3.6 million during 2009. If the Partnership pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then it 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.

The Partnership's business involves hazardous substances and may be adversely affected by environmental regulation.

Many of the operations and activities of the Partnership's gathering systems, plants and other facilities, including the 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 facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by the Partnership or locations to which it has 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 the Partnership's 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 the Partnership's business due to its handling of natural gas and other petroleum products, air emissions related to its 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 compliance costs and the cost of any remediation that may become necessary. The Partnership may incur material environmental costs and liabilities. Furthermore, its insurance may not provide sufficient coverage in the event an environmental claim is made against it.

The Partnership's 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 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 profitability.

The Partnership's success depends on key members of its management, the loss or replacement of whom could disrupt business operations.

The Partnership depends 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, the Partnership's business operations could be materially adversely affected. The Partnership does not maintain any "key man" life insurance for any officers.

Item 1B. *Unresolved Staff Comments*

We do not have any unresolved staff comments.

Item 2. *Properties*

A description of the Partnership's properties is contained in "Item 1. Business."

Title to Properties

Substantially all of the Partnership's 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. The Partnership has 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 the Partnership's pipeline was built was purchased in fee. The Partnership's processing plants are located on land that it leases or owns in fee. Their treating facilities are generally located on sites provided by producers or other parties.

We believe that the Partnership has satisfactory title to all of its 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 the Partnership's assets or from the Partnership's interest in these assets or should materially interfere with their use in the operation of the business.

Item 3. *Legal Proceedings*

Our operations and those of the Partnership are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we or the Partnership may be a defendant in various legal proceedings and litigation arising in the ordinary course of business. These include litigation on disputes related to contracts, property rights, use or damage and personal injury. Additionally, as the Partnership continues to expand operations into more urban, populated areas, such as the Barnett Shale, it 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 we believe are reasonable and prudent. However, this insurance may not 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”), 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. 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 CCNG 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, the Partnership does not believe this will have a material adverse effect on its 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 it as part of its 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, 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 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. 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 the Partnership 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. The Partnership 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 Stockholder Matters and Issuer Purchases of Equity Securities*

Our common stock is listed on the NASDAQ Global Select Market under the symbol "XTXI". Our common stock began trading on January 12, 2004. On February 17, 2009, the closing market price for our common stock was $3.00 per share and there were approximately 18,500 record holders and beneficial owners (held in street name) of the shares of our common stock.

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

	Common Stock Price Range		Cash Dividends
	High	Low	Paid per Share
2008:			
Quarter Ended December 31	$ 20.93	$ 2.19	$ 0.090
Quarter Ended September 30	34.13	24.26	0.320
Quarter Ended June 30	36.79	33.54	0.380
Quarter Ended March 31	37.37	31.55	0.360
2007:			
Quarter Ended December 31	$ 39.28	$ 35.18	$ 0.260
Quarter Ended September 30	38.03	28.91	0.240
Quarter Ended June 30	30.90	28.24	0.230
Quarter Ended March 31	33.54	27.45	0.220

Historically, we have paid to our stockholders, on a quarterly basis, dividends equal to the cash we receive from our Partnership distributions, less reserves for expenses, future dividends and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner's 2.0% general partner interest; and
- reserves our board of directors believes prudent to maintain.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors deems relevant. The Partnership's ability to make distributions is contractually restricted by the terms of its credit facility. Its credit facility contains covenants requiring it to maintain certain financial ratios. If its leverage ratio, as defined in the credit facility, falls below a certain level it will be prohibited from making distributions or from making more than the minimum quarterly distributions. Based on the Partnership's forecasted leverage ratios for 2009, it does 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, the Partnership is prohibited from making any distributions to unitholders if the distribution would cause an event of default, or an event of default existing, under its credit facility. Please read Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Description of Indebtedness." We do not anticipate making any future dividend payments after the dividend payment in February 2009 with respect to fourth quarter 2008 operating results until we begin receiving distributions from the Partnership again.

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 Plans (Excluding Securities Reflected in Column(a)) (c)
Equity Compensation Plans Approved By Security Holders(1)	824,851(2)	$ 9.54(3)	626,453
Equity Compensation Plans Not Approved By Security Holders	N/A	N/A	N/A

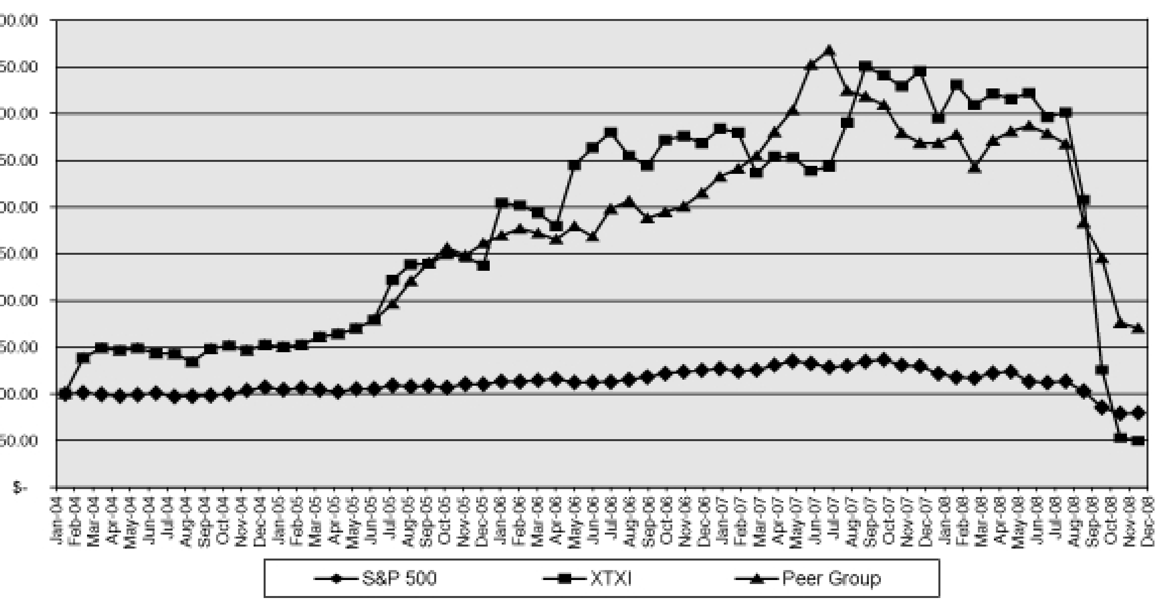
(1) Our long-term incentive plan for our officers, employees and directors was approved by our security holders in October 2006.

(2) The number of securities includes (i) 538,731 restricted shares that have been granted under our long-term incentive plan that have not vested, and (ii) 218,620 performance shares which could result in grants of restricted shares in the future.

(3) The exercise prices for outstanding options under the plan as of December 31, 2008 range from $6.50 to $13.33 per share.

Performance Graph

The following graph sets forth the cumulative total stockholder return for our common stock, the Standard & Poor's 500 Stock Index, and a peer group of publicly traded partners of publicly traded limited partnerships in the Midstream natural gas, natural gas liquids and propane industries from January 12, 2004, the date of our initial public offering, through December 31, 2008. The chart assumes that $100 was invested on January 12, 2004, with dividends reinvested. The peer group includes Atlas Pipeline Holdings, L.P., Inergy Holdings, L.P., Enterprise GP Holdings, L.P., Alliance Holdings GP, L.P. and Magellan Midstream Holdings, L.P. (Inergy Holdings, L.P.'s initial public offering was in June 2005, Enterprise GP Holdings L.P.'s initial public offering was in August 2005, Atlas Pipeline Holdings, L.P.'s initial public offering was in July 2006, Alliance Holdings GP, L.P.'s initial public offering was in May 2006, and Magellan Midstream Holdings, L.P.'s initial public offering was in February 2006, and it has been assumed that these companies performed in accordance with the peer group average prior to such dates).



Item 6. *Selected Financial Data*

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

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

	Crosstex Energy, Inc.				
	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share 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
Operating expenses	169,056	125,184	98,839	54,689	38,396
General and administrative	74,518	64,304	47,707	34,145	22,005
(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	31,240	—	—	—	981
Depreciation and amortization	131,318	106,685	80,579	33,887	20,855
Total operating costs and expenses	4,878,297	3,764,694	3,092,704	2,995,078	1,948,289
Operating income	28,752	84,394	37,382	28,202	26,831
Other income (expense):					
Interest expense, net	(102,565)	(78,993)	(51,051)	(15,332)	(9,115)
Other income (expense)	27,885	683	1,774	391	802
Total other income (expense)	(74,680)	(78,310)	(49,277)	(14,941)	(8,313)
Income (loss) from continuing operations before income taxes, gain on issuance of Partnership units and interest of non-controlling partners in the Partnership's net income (loss)	(45,928)	6,084	(11,895)	13,261	18,518
Income tax provision	(2,410)	(10,147)	(9,958)	(29,261)	(4,447)
Gain on issuance of Partnership units(1)	14,748	7,461	18,955	65,070	—

	Crosstex Energy, Inc. Years Ended December 31, 2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Interest of non-controlling partners in the Partnership's net income (loss) from continuing operations	45,593	7,246	17,213	(1,309)	(6,675)
Income (loss) from continuing operations before discontinued operations and cumulative effect of change in accounting principle	12,003	10,644	14,315	47,761	7,396
Discontinued Operations:					
Income from discontinued operations-net of tax and net of minority interest	1,266	1,532	1,970	1,375	1,304
Gain on sale of discontinued operations-net of tax and net of minority interest	10,964	—	—	—	—
Discontinued operations-net of tax and net of minority interest	12,230	1,532	1,970	1,375	1,304
Net income before cumulative effect of change in accounting principle	24,233	12,176	16,285	49,136	8,700
Cumulative effect of change in accounting principle	—	—	170	—	—
Net income	$ 24,233	$ 12,176	$ 16,455	$ 49,136	$ 8,700
Net income per common share-basic(2)	$ 0.52	$ 0.26	$ 0.39	$ 1.29	$ 0.24
Net income per common share-diluted(2)	$ 0.52	$ 0.26	$ 0.39	$ 1.26	$ 0.22
Dividends per share(2)(3):					
Common	$ 1.32	$ 0.91	$ 0.807	$ 0.563	$ 0.327
Preferred	—	—	—	—	$ 0.327
Balance Sheet Data (end of period):					
Working capital surplus (deficit)	$ (20,431)	$ (39,330)	$ (70,091)	$ 4,872	$ (18,265)
Property and equipment, net	1,528,490	1,426,546	1,107,242	668,632	325,653
Total assets	2,546,743	2,602,829	2,206,698	1,445,325	606,768
Long-term debt	1,263,706	1,223,118	987,130	522,650	148,700
Interest of non-controlling partners in the partnership	522,961	489,034	391,103	264,726	65,399
Stockholders' equity	215,429	246,366	279,413	111,247	76,933
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 170,154	$ 112,578	$ 113,839	$ 12,842	$ 46,339
Investing activities	(186,768)	(411,382)	(885,825)	(614,822)	(124,371)
Financing activities	22,720	296,022	769,717	592,365	99,072

	Crosstex Energy, Inc. Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Other Financial Data:					
Midstream gross margin	$ 370,778	$ 326,482	$ 218,176	$ 123,619	$ 89,045
Treating gross margin	50,374	45,790	42,632	29,132	19,597
Total gross margin(4)	$ 421,162	$ 372,272	$ 260,808	$ 152,751	$ 108,642
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)(5)	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) We recognized gains of $14.7 million in 2008, $7.5 million in 2007, $19.0 million in 2006 and $65.1 million in 2005 as a result of the Partnership issuing additional units in public offerings at prices per unit greater than our equivalent carrying value.

(2) Per share amounts have been adjusted for the two-for-one stock split made in conjunction with our initial public offering in January 2004 and a three-for-one stock split effected in December 2006.

(3) Dividends paid.

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

(5) Processed volumes during 2005 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 the Partnership.

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

Crosstex Energy, Inc. is a Delaware corporation formed on April 28, 2000 to engage in the gathering, transmission, treating, processing and marketing of natural gas and NGLs through its subsidiaries. On July 12, 2002, we formed Crosstex Energy, L.P., a Delaware limited partnership, to acquire indirectly substantially all of the assets, liabilities and operations of its predecessor, Crosstex Energy Services, Ltd. Our assets consist almost exclusively of partnership interests in Crosstex Energy, L.P., a publicly traded limited partnership engaged in the gathering, transmission, treating, processing and marketing of natural gas and NGLs. These partnership interests consist of (i) 16,414,830 common units, representing approximately 34.0% of the limited partner interests in Crosstex Energy, L.P., and (ii) 100% ownership interest in Crosstex Energy GP, L.P., the general partner of Crosstex Energy, L.P., which owns a 2.0% general partner interest and all of the incentive distribution rights in Crosstex Energy, L.P.

Our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. The Partnership is required by its partnership agreement to distribute all its cash on hand at the end of each quarter, less reserves established by its general partner in its sole discretion to provide for the proper conduct of the Partnership's business or to provide for future distributions.

The incentive distribution rights entitle us to receive an increasing percentage of cash distributed by the Partnership as certain target distribution levels are reached. Specifically, they entitle us to receive 13.0% of all cash distributed in a quarter after each unit has received $0.25 for that quarter, 23.0% of all cash distributed after each unit has received $0.3125 for that quarter, and 48.0% of all cash distributed after each unit has received $0.375 for that quarter.

Quarterly distributions by the Partnership had steadily increased from the first distribution of $0.25 per unit for the quarter ended March 31, 2003 to $0.63 per unit for the quarter ended June 30, 2008. The distribution for third quarter of 2008 operating results was reduced to $0.50 per unit followed by a further reduction to $0.25 per unit for the fourth quarter of 2008 (paid in February 2009). The Partnership's distributions were reduced during the last half of 2008 as a result of a decline in its cash flows from operations due to declines in natural gas and NGL prices during the last half of 2008, gross margin losses due to hurricanes Ike and Gustav and the declines in the global financial markets and economic conditions as discussed under "Item 1. Business — Crosstex Energy, L.P. — Recent Developments" and " — Business Strategy." Our distributions from the Partnership pursuant to our ownership of common units and 2.0% general partner interest, including our incentive distribution rights (IDRs), during 2008 were as follows:

- quarter ended March 31, 2008 (paid in May 2008) — $20.8 million (including $11.8 million with respect to our IDRs)
- quarter ended June 30, 2008 (paid in August 2008) — $23.4 million (including $12.3 million with respect to our IDRs)
- quarter ended September 30, 2008 (paid in November 2008) — $15.5 million (including $6.7 million with respect to our IDRs), and
- quarter ended December 31, 2008 (paid in February 2009) — $4.3 million (no IDR distributions).

In response to the recent developments, the Partnership has adjusted its business strategy for 2009 to focus on maximizing liquidity, maintaining a stable asset base, improving the profitability of its assets by increasing their utilization while controlling costs and reducing capital expenditures as discussed under "Crosstex Energy, L.P. — Business Strategies." One of the strategies included amending the Partnership's bank credit facility and its senior note agreement to negotiate terms with its creditors that will allow continued operation of its assets during the current difficult economic conditions. The amended terms of the credit facility and senior secured note agreement prohibit the Partnership from making distributions unless its leverage ratio is below certain levels and the PIK notes have been repaid. The Partnership does not expect that it will meet these conditions in 2009. Since our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own, we do not expect to receive any significant cash flows until the Partnership is able to improve its leverage ratio and begin making distributions again. As of December 31, 2008, we have $14.0 million of cash which we expect to be sufficient to pay our expenses and federal income taxes over the next several years based on our forecasted cash flows. We do not anticipate making any future dividend payments after the dividend payment in February 2009 with respect to fourth quarter 2008 operating results until we begin receiving distributions from the Partnership again.

Since we control the general partner interest in the Partnership, we reflect our ownership interest in the Partnership on a consolidated basis, which means that our financial results are combined with the Partnership's financial results and the results of our other subsidiaries. The interest owned by non-controlling partners' share of income is reflected as an expense in our results of operations. We have no separate operating activities apart from those conducted by the Partnership, and our cash flows consist almost exclusively of distributions from the Partnership on the partnership interests we own. Our consolidated results of operations are derived from the results of operations of the Partnership and also include our gains on the issuance of units in the Partnership, deferred taxes, interest of non-controlling partners in the Partnership's net income, interest income (expense) and general and administrative expenses not reflected in the Partnership's results of operation. Accordingly, the discussion of our financial position and results of operations in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" primarily reflects the operating activities and results of operations of the Partnership.

The Partnership has 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. The Partnership's Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, while the 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 the Partnership's gross margin was generated in the Midstream division, with the balance in the Treating division. The Partnership focuses on gross margin to manage its operations because its 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. The Partnership buys and sells most of its natural gas at a fixed relationship to the relevant index price so margins on gas sales. In addition, the Partnership receives certain fees for processing based on a percentage of the liquids produced and enters into hedge contracts for its expected share of the liquids produced to protect margins from changes in liquids prices.

During the past five years, the Partnership has grown significantly as a result of construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2004 through December 31, 2008, it has 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.

The Partnership's Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through its pipeline systems, processed at its processing facilities and the volumes of NGLs handled at its fractionation facilities. Treating segment margins are largely a function of the number and size of treating plants in operation. The Partnership generates Midstream revenues from six primary sources:

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

With respect to the Partnership's Midstream services, it generally gathers or transports gas owned by others through its facilities for a fee, or it buys 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 the Partnership's purchase/sale transactions, the resale price is generally based on the same index price at which the gas was purchased, and, if the Partnership is to be profitable, at a smaller discount or larger premium to the index than it was purchased. The Partnership attempts to execute all purchases and sales substantially concurrently, or it enters into a future delivery obligation, thereby establishing the basis for the margin it will receive for each natural gas transaction. The Partnership's gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas.

The Partnership also realizes margins in its Midstream segment from 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 the Partnerships margins are higher during periods of high liquid prices relative to natural gas prices. Under fee based contracts its margins are driven by throughput volume. See "— Commodity Price Risk."

The Partnership generates 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 the 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 the 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 the 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.

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, such as our investment in CELP, 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, the Partnership's 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 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 the Partnership's 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 its 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, the Partnership is not responsible for the fuel or shrink associated with processing. Under margin contracts the Partnership realizes 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 the Partnership has seen some improvement in NGL prices and the fractionation spread in the early months of 2009 over the levels experienced in December 2008, the Partnership believes that its 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 the Partnership's gross margin was attributable to gas processing as compared to 46.1% of its 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 the contractual processing arrangements used by the Partnership.

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 the 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 the Partnership's 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. The Partnership believes 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 its pipeline and gathering systems and processing through its processing plants. The Partnership has seen a decline in drilling activity by gas producers in its 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 the Partnership's customers, including one of its largest customers in the Barnett Shale, have recently announced drilling plans for 2009 that are substantially below their drilling levels during 2008.

The Partnership's business was also negatively impacted by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September 2008. Although the majority of its 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 its 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 the Partnership does not anticipate that gas production to its south Louisiana plants will recover to pre-hurricane levels until mid-2009, when all repairs are expected to be complete. Additionally, one of the Partnership's 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. 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 the Partnership's gross margin of approximately $22.9 million.

Two of the Partnership's 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, the 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 the Partnership was 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

The Partnership has 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 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 the Partnership's business during 2006, 2007 and 2008.

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 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 the Partnership's 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, the Partnership began expanding its north Texas pipeline gathering system. The continued expansion of the north Texas gathering systems to handle the growing production in the Barnett Shale was one of the Partnership's 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, the Partnership has connected 444 new wells to its gathering system and significantly increased the dedicated acreage owned by other producers. The Partnership's processing capacity in the Barnett Shale is 280 MMcf/d including the Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, the Azle plant, which is a 50 MMcf/d cryogenic processing plant, and the Goforth plant, which is a 30 MMcf/d processing plant. In 2007 and 2008, the Partnership constructed a 29-mile expansion in north Johnson County to its 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. The Partnership has 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 the north Texas gathering system was approximately 1,100 MMcf/d and total throughput on the 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, the Partnership commenced construction of an $80.0 million natural gas processing facility called Bear Creek in Hood County near its 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, the Partnership does not anticipate that the additional processing capacity provided by the Bear Creek plant will be needed until late 2010 or in 2011. Therefore, it has decided to put this construction project on hold until the demand for this processing capacity returns, at which time it will seek to obtain financing for the project. As of December 31, 2008, the Partnership has 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, the Partnership acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.7 million.

On October 3, 2006, the Partnership 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, it acquired the remaining 50% interest in the amine-treating plants for approximately $1.5 million.

The Partnership's 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, the Partnership 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 the Partnership's customer's access to premium mid-west and east coast markets.

In April 2007, the Partnership completed construction and commenced operations on its north Louisiana expansion, which is an extension of the 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 the Red River lateral. The 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 the Partnership 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.

Other Assets

We owned two inactive gas plants in addition to our limited and general partner interests in the Partnership. These two gas plants are the Jonesville processing plant and the Clarkson plant. During 2008 these two plants were transferred to the Partnership at net book value for a cash price of $0.4 million which represented the fair value of the plants.

Impact of Federal Income Taxes

Crosstex Energy, Inc. is a corporation for federal income tax purposes. As such, our federal taxable income is subject to tax at a maximum rate of 35.0% under current law. We expect to have taxable income allocated to us as a result of our investment in the Partnership's units, particularly because of remedial allocations that will be made among the unitholders. Taxable income allocated to us by the Partnership will increase over the years as the results of operation increase and as the ratio of income to distributions increases for all of the unitholders.

As of December 31, 2008 we have a net operating loss carry forward of $108.6 million for federal income taxes and state loss carry forwards of $46.4 million. We believe it is more likely than not that our future results of operations will generate sufficient taxable income to utilize these net operating loss carry forwards before they expire. Once these net operating loss carry forwards are fully utilized, we will have to pay tax on our federal taxable income at a maximum rate of 35.0% under current law.

Our use of this net operating loss carry forward will be limited if there is a greater than 50.0% change in our stock ownership over a three year period.

Commodity Price Risk

The Partnership's business is subject to significant risks due to fluctuations in commodity prices. Its exposure to these risks is primarily in the gas processing component of its business. A large percentage of the processing fees are realized under POL contracts that are directly impacted by the market price of NGLs. It also realizes 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 the Partnership's 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 the Partnership is 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. The Partnership has a number of fractionation margin contracts on its Plaquemine and Gibson processing plants that expose it to the fractionation spread. Under these margin contracts its 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 the Partnership's margins, and may negatively impact its gross margin further if such declines continue.

The Partnership is also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of its gathering and transportation services. Approximately 4.0% of the natural gas it markets 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, 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. The Partnership's gathering systems in the region and NTP accounted for $41.3 million and $9.1 million of this increase, respectively. The Partnership's 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.

The Partnership's 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. The Partnership estimates that these storms resulted in 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 on line 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%. The Partnership 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 $169.1 million for the year ended December 31, 2008 compared to $125.2 million for the year ended December 31, 2007, an increase of $43.9 million, or 35.0%. 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 $74.5 million for the year ended December 31, 2008 compared to $64.3 million for the year ended December 31, 2007, an increase of $10.2 million, or 15.9%. 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;
- $2.5 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	
	Total	Realized	Total	Realized
(Gain)/Loss on Derivatives:				
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 $31.2 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 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 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.
- $5.7 million related to goodwill — We determined that the carrying amount of goodwill attributable to the Partnership's Midstream segment was impaired because of the significant decline in its 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 our 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 $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 the Partnership's future operations.

Depreciation and Amortization. Depreciation and amortization expenses were $131.3 million for the year ended December 31, 2008 compared to $106.7 million for the year ended December 31, 2007, an increase of $24.6 million, or 23.1%. 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 $102.6 million for the year ended December 31, 2008 compared to $79.0 million for the year ended December 31, 2007, an increase of 23.6 million, or 29.8%. The increase relates primarily to the negative impact of declining interest rates on 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	(0.4)	(1.1)
Other	6.5	3.9
Total	$ 102.6	$ 79.0

Other Income. Other income was $27.9 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.

Gain on Issuance of Units of the Partnership. As a result of the Partnership issuing common units in April 2008 to unrelated parties at a price per unit greater than our equivalent carrying value, our share of net assets of the Partnership increased by $14.7 million and we recognized a gain on issuance of such units.

Income Taxes. We provide income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. Income tax expense was $2.4 million and $10.1 million for the years ended December 31, 2008 and 2007, respectively, a decrease of $7.7 million related to a decrease in income generated by operations and the $5.2 million decrease in the valuation allowance for investment in the Partnership.

Interest of Non-Controlling Partners in the Partnership's Net Income (Loss) from Continuing Operations. The interest of non-controlling partners in the Partnership's net loss increased by $38.3 million to a loss of $45.6 million for the year ended December 31, 2008 compared to a loss of $7.3 million for the year ended December 31, 2007 due to the changes shown in the following summary (in millions):

	Years Ended December 31,	
	2008	2007
Net income (loss) from continuing operations for the Partnership	$ (44.8)	$ 7.4
(Income) allocation to CEI for the general partner incentive distribution	(30.8)	(24.8)
Stock-based compensation costs allocated to CEI for its stock options and restricted stock granted to Partnership officers, employees and directors	4.7	5.4
Loss allocation to CEI for its 2% general partner share of Partnership loss	0.8	0.2
Net loss allocable to limited partners	(70.1)	(11.8)
Less: CEI's share of net loss allocable to limited partners	24.2	4.3
Plus: Non-controlling partners' share of net income in Crosstex Denton County Gathering, J.V	0.3	0.2
Non-controlling partners' share of Partnership net loss from continuing operations	$ (45.6)	$ (7.3)

The general partner incentive distributions increased between these years due to an increase in the distribution amounts per unit and due to an increase in the number of common units outstanding.

Discontinued Operations. Discontinued operations were $12.2 million for the year ended December 31, 2008 compared to $1.5 million for the year ended December 31, 2007. In November 2008, the Partnership sold its undivided 12.4% interest in the Seminole gas processing plant to an unrelated third party. The Company realized a gain on the sale of $11.0 million net of tax and minority interest.

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.

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

In addition, the Partnership has the ability to buy gas from and to sell gas to various gas markets through its pipeline systems. During 2007, the Partnership was able to benefit from price differentials between the various gas markets by selling gas into markets with more favorable pricing thereby improving its 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 $125.2 million for the year ended December 31, 2007 compared to $98.8 million for the year ended December 31, 2006, an increase of $26.3 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 $64.3 million for the year ended December 31, 2007 compared to $47.7 million for the year ended December 31, 2006, an increase of $16.6 million, or 34.8%. 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	
	Total	Realized	Total	Realized
(Gain) Loss on Derivatives:				
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, 2007. The 2007 gain was primarily generated from the disposition of unused catalyst material and the disposition of a treating plant. The gain in 2006 is primarily related to the sale of inactive gas processing facilities acquired as part of the south Louisiana processing assets and as part of the LIG acquisition.

Depreciation and Amortization. Depreciation and amortization expenses were $106.7 million for the year ended December 31, 2007 compared to $80.6 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 $79.0 million for the year ended December 31, 2007 compared to $51.1 million for the year ended December 31, 2006, an increase of $27.9 million, or 54.7%. 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	(1.1)	(1.4)
Other	3.9	4.3
Total	$ 79.0	$ 51.1

Other Income. Other income was $0.7 million for the year ended December 31, 2007 compared to $1.8 million for the year ended December 31, 2006. In 2006 we collected $1.6 million in excess of the carrying value of the Enron account receivable net of the allowance.

Gain on Issuance of Units of the Partnership. As a result of the Partnership issuing common units in December 2007 to unrelated parties at a price per unit greater than our equivalent carrying value, our share of net assets of the Partnership increased by $7.5 million and we recognized a gain on issuance of such units. In 2006, we recognized a $19.0 million gain associated with the issuance in June 2005 of senior subordinated units when the senior subordinated units converted to common units in February 2006.

Income Taxes. We provide income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. Income tax expense was $10.1 million and $10.0 million for the years ended December 31, 2007 and 2006, respectively.

Interest of Non-Controlling Partners in the Partnership's Net Income (Loss) from Continuing Operations. The interest of non-controlling partners in the Partnership's net income increased by $9.9 million to a loss of

$7.3 million for the year ended December 31, 2007 compared to a loss of $17.2 million for the year ended December 31, 2006 due to the changes shown in the following summary (in millions):

	Years Ended December 31, 2007	2006
Net income (loss) from continuing operations for the Partnership	$ 7.4	$ (12.2)
(Income) allocation to CEI for the general partner incentive distribution	(24.8)	(20.4)
Stock-based compensation costs allocated to CEI for its stock options and restricted stock granted to Partnership officers, employees and directors	5.4	3.5
Loss allocation to CEI for its 2% general partner share of Partnership loss	0.2	0.6
Net loss allocable to limited partners	(11.8)	(28.5)
Less: CEI's share of net loss allocable to limited partners	4.3	11.1
Plus: Non-controlling partners' share of net income in Crosstex Denton County Gathering, J.V.	0.2	0.2
Non-controlling partners' share of Partnership net loss from continuing operations	$ (7.3)	$ (17.2)

The general partner incentive distributions increased between these years due to an increase in the distribution amounts per unit and due to an increase in the number of common units outstanding.

Discontinued Operations. Discontinued operations were $1.5 million for the year ended December 31, 2007 compared to $2.0 million for the year ended December 31, 2006. In November 2008, the Partnership sold its 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. 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. It 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 utilizes 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. It uses 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. The Partnership believes that its accrual process for the one to two months of sales and purchases provides a reasonable estimate of such sales and purchases.

The Partnership engages in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas and natural gas liquids. The Partnership manages its 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 its future commitments and significantly reduce its risk to the movement in natural gas prices.

The Partnership uses derivatives to hedge against changes in cash flows related to product prices and interest rate risk, 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.

The Partnership conducts “off-system” gas marketing operations as a service to producers on systems that it does not own. The Partnership refers to these activities as part of 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. In other cases, the Partnership purchases the natural gas from the producer and enters 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.

The Partnership manages its 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, 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 it uses 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.

Sales of Securities by Subsidiaries. We recognize gains and losses in the consolidated statements of operations resulting from subsidiary sales of additional equity interest, including the Partnership’s limited partnership units, to unrelated parties.

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*, the Partnership evaluates 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 the Partnership’s long-lived assets has occurred, it must estimate the undiscounted cash flows attributable to the asset. The 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;
- the Partnership’s ability to negotiate favorable sales agreements;

- the risks that natural gas exploration and production activities will not occur or be successful;
- the Partnership's 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 the Partnership's 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 owned by the Partnership. The Partnership capitalizes 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. The Partnership capitalizes the costs of renewals and betterments that extend the useful life, while we expense the costs of repairs, replacements and maintenance projects as incurred.

The Partnership generally computes 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, depreciation estimates may be reviewed 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 $170.2 million, $112.6 million and $113.8 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	$ 157.6	$ 136.4	$ 88.2
Changes in working capital	12.5	(23.9)	25.6

The primary reason for the increased cash flow from income before non-cash income and expenses of $21.2 million from 2007 to 2008 was increased operating income from the Partnership's expansion 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 $48.2 million from 2006 to 2007 was increased operating income from the Partnership's 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 in the Partnership, net of accrued amounts, as follows (in millions):

	Years Ended December 31,		
	2008	2007	2006
Growth capital expenditures	$ 257.2	$ 403.7	$ 308.8
Acquisitions and asset purchases	—	—	576.1
Maintenance capital expenditures	18.3	10.8	6.0
Total	$ 275.5	$ 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 $22.7 million, $296.0 million and $769.7 million for the years ended December 31, 2008, 2007 and 2006, respectively. Our financing activities primarily relate to funding of capital expenditures and acquisitions in the Partnership. Our financings have primarily consisted of borrowings under the Partnership's bank credit facility, borrowings under capital lease obligations, equity offerings and senior note issuances in the Partnership 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
Common unit offerings	101.9	58.8	—
Net borrowings under capital lease obligations	23.9	3.6	—
Senior subordinated unit offerings	—	102.6	368.3

Dividends to shareholders and distributions to non-controlling partners in the Partnership represent our primary use of cash in financing activities. Total cash distributions made during the last three years were as follows (in millions):

	Years Ended December 31,		
	2008	2007	2006
Dividends to shareholders	$ 62.0	$ 42.6	$ 34.7
Non-controlling partners	63.2	39.0	34.9
Total	$ 125.2	$ 81.6	$ 69.6

In order to reduce our interest costs, the Partnership does 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 $20.4 million as of December 31, 2008, primarily due to drafts payable of $21.5 million as of the same date. Changes in working capital may fluctuate significantly between periods even though the Partnership's trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of its revenues are collected and a large volume of its 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 may fluctuate significantly depending on the timing of these receipts and payments. In addition, although the Partnership strives to minimize 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. Working capital also includes mark to market derivative assets and liabilities associated with commodity derivatives which may fluctuate significantly due the changes in natural gas and NGL prices and associated with 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, the Partnership 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. Net proceeds from the issuance, including our general partner contribution less expenses associated with the issuance, were approximately $102.0 million.

December 2007 Sale of Common Units. On December 19, 2007, the Partnership 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. We made a general partner contribution of $1.2 million in connection with the issuance to maintain our 2% general partner interest.

March 2007 Sale of Senior Subordinated Series D Units. On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests 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. We made a general partner contribution of $2.7 million in connection with this issuance to maintain our 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 unit 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 the Partnership until March 23, 2009.

June 2006 Sale of Senior Subordinated Series C Units. On June 29, 2006, the Partnership 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. We purchased 6,414,830 of the senior subordinated series C units and made a general partner contribution of $9.0 million in connection with this issuance to maintain our 2% general partner interest. The senior subordinated series C units automatically converted to common units on 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 the Partnership has been successful in accessing capital from both the equity market and financial institutions to fund the growth of its operations. However, due to the lack of liquidity in the financial and equity markets coupled with the decline in our Midstream operations, the Partnership's access to capital is expected to be severely limited in 2009. As a result the Partnership has significantly reduced its growth plans during 2009 and 2010 to operate within the existing capital structure.

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

The Partnership lowered its 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 its credit facility and senior secured note agreement restrict its ability to make distributions unless certain conditions are met. The Partnership does not expect that it will meet these conditions in 2009.

The Partnership has reduced 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. The Partnership will use cash flow from operations and existing capacity under its bank credit facility to fund its 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 the bank credit facility. It is unlikely that the Partnership will be able to make any acquisitions based on the terms of its credit facility and senior secured note agreement and the condition of the capital markets because it 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.

The Partnership has reduced general and administrative expenses by reducing its work force by approximately 8.0% through the elimination of open positions and elimination of certain corporate positions and minimizing all non-essential costs. It also reduced 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 the Partnership's 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 Partnership's interest payable under its 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, 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 its 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 the credit facility to, among other things, (i) increase the maximum permitted leverage ratio the Partnership must maintain for the fiscal quarters ending December 31, 2008 through September 30, 2009, (ii) lower the minimum interest coverage ratio the Partnership must maintain for the fiscal quarter ending December 31, 2008 and each fiscal quarter thereafter, (iii) permit the Partnership to sell certain assets, (iv) increase the interest rate the Partnership pays on the obligations under the credit facility and (v) lowers the maximum permitted leverage ratio the Partnership must maintain if it 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 the bank credit facility and the senior secured note agreement. On February 27, 2009, the Partnership entered into the Sixth Amendment to Fourth Amended and Restated Credit Agreement and Consent (the "Sixth Amendment") to its credit facility with the Bank Lending Group. Under the Sixth Amendment, borrowings will bear interest at the Partnership's 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 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 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, the Partnership must pay a leverage fee on such date, equal to the product of the total amounts outstanding under its 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 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 the fiscal quarters ending March 31, 2011 thru March 31, 2012; and

- 4.25 to 1.00 for the fiscal quarters ending June 20, 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 quarter 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 quarters ending September 30, 2010 and December 31, 2010;
- 2.50 to 1.00 for any fiscal quarters ending March 31, 2011, and thereafter.

Under the Sixth Amendment, no quarterly distributions may be paid to unitholders of the Partnership 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 unitholders from available cash as provided by the 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. In order to repay the PIK notes prior to their scheduled maturity, the Partnership will need to amend or refinance its bank credit facility. Based on the Partnership's forecasted leverage ratios for 2009 and the Partnership's near term ability to refinance its bank credit facility, it does 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 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 its credit facility and the current condition of the capital markets because the Partnership 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 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 the Partnership 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 the Partnership's 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.

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) Principle 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 its 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 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 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 the 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 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 of 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 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 equity interests in substantially all of the Partnership's 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 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 the Partnership's 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 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 Partnership's bank credit facility, holders of its senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under the Partnership's 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 the Partnership's customers are a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers and other counterparties, such as lenders and hedging counterparties. Any increase in the nonpayment and nonperformance by its customers could adversely affect the results of operations and reduce the Partnership's ability to make distributions to its unitholders. Many of the Partnership's 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 the Partnership's 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 customers' liquidity and ability to make payments or perform on their obligations to the Partnership. Furthermore, some of the 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 the Partnership.

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

The Partnership's operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We believe the Partnership is 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, 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 it 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 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, 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 us 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 the Partnership 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. The Partnership 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 Company 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's Emerging Issues Task Force ("EITF") reached a consensus on EITF 06-11 *"Accounting for Income Tax Benefits of Dividends on Share Based Payment Awards".* The tax benefit received on dividends associated with share-based awards that are charged to retained earnings should be recorded in additional paid-in-capital ("APIC") and included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. The consensus is effective for the tax benefits of dividends declared in fiscal years beginning after December 15, 2007. The Company has evaluated the impact of the EITF and determined we will not recognize any tax benefit or a related credit to additional paid in capital for dividends on restricted stock charged to retained earnings. The tax benefit and credit to the APIC pool will be recognized when the tax deduction reduces income taxes payable after utilization of our net operating loss carry forward.

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 162 is effective for fiscal years beginning after November 15, 2008. The Company 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 Company 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. The Partnership’s primary market risk is the risk related to changes in the prices of natural gas and NGLs. In addition, it is exposed to the risk of changes in interest rates on its floating rate debt.

Interest Rate Risk

The Partnership is exposed to interest rate risk on its variable rate bank credit facility. At December 31, 2008 and 2007, the bank credit facility had outstanding borrowings of $784.0 million and $734.0 million, respectively, which approximated fair value. The Partnership manages a portion of its interest rate exposure on variable rate debt by utilizing interest rate swaps, which allows conversion of a portion of variable rate debt into fixed rate debt. In January 2008, the Partnership amended its 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, the Partnership 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 the Partnership 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 the financial statements. The Partnership estimates 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 its bank credit facility as of December 31, 2008, the Partnership estimates that a 1% increase or decrease in the interest rate would change its 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, the Partnership had total fixed rate debt obligations of $479.7 million and $489.1 million, respectively, consisting of its 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. The Partnership estimates that a 1% increase or decrease in interest rates would increase or decrease the fair value of the fixed rated debt (its senior secured notes) by $15.2 million based on the debt obligations as of December 31, 2008.

Commodity Price Risk

The Partnership is subject to significant risks due to fluctuations in commodity prices. Its exposure to these risks is primarily in the gas processing component of its business. The Partnership currently processes gas under three main types of contractual arrangements:

1. *Processing margin contracts:* Under this type of contract, the Partnership pays the producer for the full amount of inlet gas to the plant, and makes 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. The Partnership's 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, the Partnership mitigates its risk of processing natural gas when its margins are negative under its current processing margin contracts primarily through its ability to bypass processing when it is not profitable for the Partnership, 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, the Partnership receives 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, its margins from these contracts are greater during periods of high liquids prices. The Partnership's 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 the Partnership has no commodity price exposure, and is 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%

The Partnership has hedges in place at December 31, 2008 covering liquids volumes it expects 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	We Receive	Fair Value Asset/(Liability) (In thousands)
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

The Partnership has hedged its exposure to declines in prices for NGL volumes produced for its account. The NGL volumes hedged, as set forth above, focus on POL contracts. The Partnership hedges POL exposure based on volumes considered 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. The Partnership hedged 44% of its hedgeable volumes at risk through the end of 2009 (20% of total volumes at risk through the end of 2009). The Partnership currently has not hedged any of its processing margin volumes for 2009.

The Partnership is also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of its gathering and transport services. Approximately 4.0% of the natural gas the Partnership markets 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, resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices. The Partnership has hedged 34% of its 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 the Partnership's principal gathering and transmission systems and for its commercial services business for the year ended December 31, 2008.

Asset or Business	Years Ended December 31, 2008 — Gas Purchased — Fixed Amount to Index	Gas Purchased — Percentage of Index	Gas Sold — Fixed Amount to Index	Gas Sold — 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 certain assets included in the south Texas system and other assets.

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

Another price risk the Partnership faces is the risk of mismatching volumes of gas bought or sold on a monthly price versus volumes bought or sold on a daily price. The Partnership enters 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 it with short or long positions that must be covered. The Partnership uses financial swaps to mitigate the exposure at the time it is created to maintain a balanced position.

The Partnership's primary commodity risk management objective is to reduce volatility in its cash flows. The Partnership maintains a risk management committee, including members of senior management, which oversees all hedging activity. The Partnership enters 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 its risk management committee.

The use of financial instruments may expose the Partnership 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) counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that the Partnership engages in hedging activities it may be prevented from realizing the benefits of favorable price changes in the physical market. However, the Partnership is 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-49 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 our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, our 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, the Partnership entered into the Sixth Amendment to its 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 its 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 10.13 and 10.18, 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*

The following table shows information about our executive officers. Executive officers serve until their successors are elected or appointed.

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis(1)	47	President, Chief Executive Officer and Director
Robert S. Purgason	52	Executive Vice President -- Chief Operating Officer
William W. Davis(1)	55	Executive Vice President and Chief Financial Officer
Joe A. Davis(1)	48	Executive Vice President, General Counsel and Secretary

(1) Not related.

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 also serves as a director of Crosstex Energy GP, LLC, the general partner of the general partner of the Partnership. 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. Mr. Davis has served as our Chief Financial Officer since joining our predecessor. 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.

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 bachelor of science from the University of Texas in Dallas.

Code of Ethics

We adopted a Code of Business Conduct and Ethics applicable to all of our employees, officers, and directors, with regard to company-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. The Code also incorporates our expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission 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, Inc., 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 grant any waiver, including any implicit waiver, from a provision of the Code to any of our executive officers and directors, we will disclose the nature of such amendment or waiver in a report on Form 8-K.

Other

The sections entitled "Proposal One: Election of Directors", "Additional Information Regarding the Board of Directors", "Section 16(a) Beneficial Ownership Reporting Compliance", and "Stockholder Proposals and Other Matters" that will appear in our proxy statement for the 2009 annual meeting of stockholders, which we expect to file with the Securities and Exchange Commission within 120 days after December 31, 2008 (the "2009 Proxy Statement"), will set forth certain information with respect to our directors and with respect to reporting under Section 16(a) of the Securities Exchange Act of 1934, and are incorporated herein by reference.

Item 11. ***Executive Compensation***

The section entitled "Executive Compensation" that will appear in the 2009 Proxy Statement will set forth certain information with respect to the compensation of our management, and is incorporated herein by reference.

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

The sections entitled "Equity Compensation Plans" and "Security Ownership of Certain Beneficial Owners and Management" that appears in the 2009 Proxy Statement will set forth certain information with respect to securities authorized for issuance under equity compensation plans and the ownership of voting securities and equity securities of us, and are incorporated herein by reference.

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

The sections entitled "Certain Relationships and Related Party Transactions" and "Additional Information Regarding the Board of Directors" that will appear in the 2009 Proxy Statement will set forth certain information with respect to certain relationships and related party transactions, and are incorporated herein by reference.

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

The section entitled "Fees Paid to Independent Public Accounting Firm" that will appear in the 2009 Proxy Statement will set forth certain information with respect to accounting fees and services, and is incorporated herein by reference.

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 I — Parent Company Statements on page F-39 and Schedule II — Valuation and Qualifying Accounts on Page F-45.

(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	—	Amended and Restated Certificate of Incorporation of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006).
3.2	—	Third Amended and Restated Bylaws of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated March 22, 2006, filed with the Commission on March 28, 2006).
3.3	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.4	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
3.5	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.6	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008).
3.7	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference from Exhibit 3.3 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.9	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).

Number		Description
3.10	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference from Exhibit 3.6 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.11	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference from Exhibit 3.7 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.12	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference from Exhibit 3.8 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
4.1	—	Specimen Certificate representing shares of common stock (incorporated by reference from Exhibit 4.1 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
4.2	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy, Inc., Chieftain Capital Management, Inc., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LB I Group Inc., Lubar Equity Fund, LLC and Tortoise North American Energy Corp. (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).
10.1	—	Omnibus Agreement dated December 17, 2002, among Crosstex Energy, Inc. and certain other parties (incorporated by reference from Exhibit 10.5 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.2†	—	Form of Indemnity Agreement (incorporated by reference from Exhibit 10.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.3†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan dated July 12, 2002 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.4†	—	Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.5	—	Agreement Regarding 2003 Registration Statement and Waiver and Termination of Stockholders' Agreement, dated October 27, 2003 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.6†	—	Crosstex Energy, Inc. Amended and Restated Long-Term Incentive Plan effective as of September 6, 2006 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006).
10.7	—	Registration Rights Agreement, dated December 31, 2003 (incorporated by reference from Exhibit 10.6 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.8	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.9	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).
10.10	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.11	—	Third Amendment to Fourth Amended and Restated Credit Agreement, effective as of March 28, 2007, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).

Number		Description
10.12	—	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 Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008).
10.13	—	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 (incorporated by reference to Exhibit 10.6 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008).
10.14	—	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 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated September 19, 2007, filed with the Commission on September 24, 2007).
10.15	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
10.16	—	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 to Crosstex Energy, L.P.'s Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.17	—	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 Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008).
10.18	—	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 (incorporated by reference to Exhibit 10.11 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008).
10.19	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.20	—	Stock Purchase Agreement, dated as of May 16, 2006, by and among Crosstex Energy, Inc. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated May 16, 2006, filed with the Commission on May 17, 2006).
10.21	—	Senior Subordinated Series D Unit Purchase Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. an deach of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
10.22	—	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 Crosstex Energy, L.P.'s Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
10.23†	—	Form of Performance Share Agreement (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007).
10.24†	—	Form of Performance Unit Agreement (incorporated by reference to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007).

Number		Description
10.25†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.26	—	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., LB I Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.27	—	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 Crosstex Energy, L.P.'s Form 8-K dated April 9, 2008).
21.1*	—	List of Subsidiaries.
23.1*	—	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.

* 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, INC.

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 by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	March 2, 2009
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	March 2, 2009
/s/ JAMES C. CRAIN James C. Crain	Director	March 2, 2009
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Lead Director	March 2, 2009
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	March 2, 2009
/s/ CECIL E. MARTIN Cecil E. Martin	Director	March 2, 2009
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	March 2, 2009
/s/ WILLIAM W. DAVIS 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, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting (Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended) and for the assessment of the effectiveness of internal control over financial reporting for Crosstex Energy, Inc. (the "Company"). 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, Inc.'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 Company'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 Company's transactions and dispositions of the Company'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 Company's management and directors; 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 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 Company's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Company'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 Company'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 Company'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 Company's consolidated financial statements included in this report, has issued an attestation report on the Company'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

To the Board of Directors and the Stockholders of Crosstex Energy, Inc.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in stockholders' 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 schedules. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules 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, Inc. 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 schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company'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 reported dated March 2, 2009, expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Dallas, Texas
March 2, 2009

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Crosstex Energy, Inc.:

We have audited Crosstex Energy, Inc.'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 Company'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 Company'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 Company 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 Company 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.

KPMG LLP

Dallas, Texas
March 2, 2009

CROSSTEX ENERGY, INC.

Consolidated Balance Sheets

	December 31, 2008	December 31, 2007
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,959	$ 7,853
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
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	9,658	16,098
Total current assets	404,147	529,851
Property and equipment:		
Transmission assets	474,771	468,692
Gathering systems	614,572	460,420
Gas plants	577,250	565,464
Other property and equipment	72,106	65,561
Construction in process	86,462	79,889
Total property and equipment	1,825,161	1,640,026
Accumulated depreciation	(296,671)	(213,480)
Total property and equipment, net	1,528,490	1,426,546
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	25,402
Other assets, net	11,709	9,617
Total assets	$ 2,546,743	$ 2,602,829
LIABILITIES AND STOCKHOLDERS' 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	63,938	59,305
Total current liabilities	424,578	569,181
Long-term debt	1,254,294	1,213,706
Other long-term liabilities	24,708	3,553
Deferred tax liability	81,998	71,563
Fair value of derivative liabilities	22,775	9,426
Interest of non-controlling partners in the Partnership	522,961	489,034
Commitments and contingencies	—	—
Stockholders' equity:		
Common stock (150,000,000 shares authorized, $.01 par value, 46,341,621 and 46,019,235 issued and outstanding in 2008 and 2007, respectively)	464	463
Additional paid-in capital	268,988	267,859
Accumulated deficit	(54,693)	(16,878)
Accumulated other comprehensive income (loss)	670	(5,078)
Total stockholders' equity	215,429	246,366
Total liabilities and stockholders' equity	$ 2,546,743	$ 2,602,829

See accompanying notes to consolidated financial statements

CROSSTEX ENERGY, INC.

Consolidated Statements of Operations

	Years Ended December 31,		
	2008	2007	2006
	(In thousands, except per share 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	169,056	125,184	98,839
General and administrative	74,518	64,304	47,707
Gain on derivatives	(12,203)	(6,628)	(1,591)
Gain on sale of property	(1,519)	(1,667)	(2,108)
Impairments	31,240	—	—
Depreciation and amortization	131,318	106,685	80,579
Total operating costs and expenses	4,878,297	3,764,694	3,092,704
Operating income	28,752	84,394	37,382
Other income (expense):			
Interest expense, net of interest income	(102,565)	(78,993)	(51,051)
Other income	27,885	683	1,774
Total other income (expense)	(74,680)	(78,310)	(49,277)
Income (loss) from continuing operations before income taxes, gain on issuance of Partnership units and interest of non-controlling partners in the Partnership's net income (loss)	(45,928)	6,084	(11,895)
Income tax provision from continuing operations	(2,410)	(10,147)	(9,958)
Gain on issuance of units of the Partnership	14,748	7,461	18,955
Interest of non-controlling partners in the Partnership's net income (loss) from continuing operations	45,593	7,246	17,213
Income from continuing operations before discontinued operations and cumulative effect of change in accounting principle	12,003	10,644	14,315
Discontinued operations:			
Income from discontinued operations-net of tax and net of minority interest	1,266	1,532	1,970
Gain on sale of discontinued operations-net of tax and net of minority interest	10,964	—	—
Discontinued operations-net of tax and net of minority interest	12,230	1,532	1,970
Net income before cumulative effect of change in accounting principle	24,233	12,176	16,285
Cumulative effect of change in accounting principle	—	—	170
Net income	$ 24,233	$ 12,176	$ 16,455
Net income from continuing operations before discontinued operations and cumulative effect of change in accounting principle per common share:			
Basic	$ 0.26	$ 0.23	$ 0.34
Diluted	$ 0.26	$ 0.23	$ 0.34
Net income from discontinued operations per common share:			
Basic	$ 0.26	$ 0.03	$ 0.05
Diluted	$ 0.26	$ 0.03	$ 0.05
Cumulative effect of change in accounting principle per common share:			
Basic	—	—	—
Diluted	—	—	—
Net income per common share:			
Basic	$ 0.52	$ 0.26	$ 0.39
Diluted	$ 0.52	$ 0.26	$ 0.39
Weighted-average shares outstanding:			
Basic	46,298	45,988	42,168
Diluted	46,589	46,607	42,666
Dividends per share:			
Common	$ 1.32	$ 0.91	$ 0.807

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Changes in Stockholders' Equity
Years Ended December 31, 2008, 2007 and 2006

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total Stockholders' Equity
			(In thousands)			
Balance, December 31, 2005	12,760	$ 127	$ 80,187	$ 31,747	$ (814)	$ 111,247
Three-for-one common stock split	30,628	309	(309)	—	—	—
Issuance of common stock, net of offering costs	2,550	26	179,694	—	—	179,720
Proceeds from exercise of stock options	3	1	125	—	—	126
Stock-based compensation	—	—	3,567	—	—	3,567
Common dividends	—	—	—	(34,667)	—	(34,667)
Net income	—	—	—	16,455	—	16,455
Hedging gains or losses reclassified to earnings	—	—	—	—	(1,361)	(1,361)
Adjustment in fair value of derivatives	—	—	—	—	4,326	4,326
Balance, December 31, 2006	45,941	463	263,264	13,535	2,151	279,413
Conversion of restricted stock to common, net of shares withheld for taxes	63	—	(919)	—	—	(919)
Proceeds from exercise of stock options	15	—	98	—	—	98
Stock-based compensation	—	—	5,416	—	—	5,416
Common dividends	—	—	—	(42,589)	—	(42,589)
Net income	—	—	—	12,176	—	12,176
Non-controlling partners' share of other comprehensive income in Partnership	—	—	—	—	281	281
Hedging gains or losses reclassified to earnings	—	—	—	—	(963)	(963)
Adjustment in fair value of derivatives	—	—	—	—	(6,547)	(6,547)
Balance, December 31, 2007	46,019	463	267,859	(16,878)	(5,078)	246,366
Conversion of restricted stock to common, net of shares withheld for taxes	285	—	(3,815)	—	—	(3,815)
Proceeds from exercise of stock options	38	1	243	—	—	244
Stock-based compensation	—	—	4,701	—	—	4,701
Common dividends	—	—	—	(62,048)	—	(62,048)
Net income	—	—	—	24,233	—	24,233
Non-controlling partners' share of other comprehensive income in Partnership	—	—	—	—	431	431
Hedging gains or losses reclassified to earnings	—	—	—	—	4,689	4,689
Adjustment in fair value of derivatives	—	—	—	—	628	628
Balance, December 31, 2008	46,342	$ 464	$ 268,988	$ (54,693)	$ 670	$ 215,429

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Comprehensive Income

	Years Ended December 31, 2008	2007	2006
	(In thousands)		
Net income	$ 24,233	$ 12,176	$ 16,455
Non-controlling partners' share of other comprehensive income in the Partnership, net of taxes of $254, $103 and $0, respectively	431	281	—
Hedging gains or losses reclassified to earnings, net of taxes of $2,765, $(564) and $(779), respectively	4,689	(963)	(1,361)
Adjustment in fair value of derivatives, net of taxes of $372, $(3,783) and $2,460, respectively	628	(6,547)	4,326
Comprehensive income	$ 29,981	$ 4,947	$ 19,420

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Cash Flows

	Years Ended December 31, 2008	2007	2006
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 24,233	$ 12,176	$ 16,455
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	133,030	108,926	82,792
Non-cash stock-based compensation	11,279	12,259	8,579
Cumulative effect of change in accounting principle	—	—	(170)
Gain on sale of property	(51,325)	(1,667)	(2,108)
Impairment	31,240	—	—
Deferred tax expense	7,022	10,338	11,386
Interest of non-controlling partners in the Partnership net income	(9,470)	(3,198)	(13,027)
Gain on issuance of units of the Partnership	(14,748)	(7,461)	(18,955)
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	156,280	(121,285)	78,338
Natural gas and natural gas liquids, prepaid expenses and other	5,199	(5,498)	12,999
Accounts payable, accrued gas purchases, and other accrued liabilities	(148,950)	102,096	(65,694)
Fair value of derivatives	—	835	—
Net cash provided by operating activities	170,154	112,578	113,839
Cash flows from investing activities:			
Additions to property and equipment	(275,548)	(414,452)	(314,766)
Acquisitions and asset purchases	—	—	(576,110)
Proceeds from sale of property	88,780	3,070	5,051
Net cash used in investing activities	(186,768)	(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)
Distributions to non-controlling partners in the Partnership	(63,149)	(38,960)	(34,902)
Common dividends paid	(62,048)	(42,589)	(34,667)
Proceeds from exercise of common stock option	244	98	126
Conversion of restricted units, net of units withheld for taxes	(1,536)	(329)	—
Conversion of restricted stock, net of shares withheld for taxes	(3,815)	(919)	—
Net proceeds from issuance of units of the Partnership	99,888	157,491	179,185
Proceeds from exercise of Partnership unit options	850	1,598	3,328
Contributions from non-controlling partners in the Partnership	109	—	—
Net proceeds from issuance of common stock	—	—	179,720
Net cash provided by financing activities	22,720	296,022	769,717
Net increase (decrease) in cash and cash equivalents	6,106	(2,782)	(2,269)
Cash and cash equivalents, beginning of period	7,853	10,635	12,904
Cash and cash equivalents, end of period	$ 13,959	$ 7,853	$ 10,635

Cash paid for interest	$	76,291	$	79,648	$	46,794
Cash paid (refunded) for income taxes	$	1,821	$	(45)	$	(847)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements
December 31, 2008 and 2007

(1) Organization and Summary of Significant Agreements:

(a) Description of Business

CEI, a Delaware corporation formed on April 28, 2000, is engaged, through its subsidiaries, in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids (NGLs). The Company 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 Company 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) Organization

On July 12, 2002, the Company formed Crosstex Energy, L.P. (herein referred to as the Partnership or CELP), a Delaware limited partnership. Crosstex Energy GP, L.P., a wholly owned subsidiary of the Company, is the general partner of the Partnership. The Company owns 16,414,830 common units in the Partnership through its wholly-owned subsidiaries on December 31, 2008 which represented 34.0% of the limited partner interests in the Partnership.

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities and results of operations of the Company and its majority owned subsidiaries, including the Partnership. The Company proportionately consolidates the Partnership's 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 Company 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 6. The consolidated operations are hereafter referred to collectively as the Company. 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 Company 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 Company 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

Inventories of products consist of natural gas and natural gas liquids. The Company reports these assets at the lower of cost or market.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

(d) Property, Plant, and Equipment

Property, plant and equipment consists 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. Interests 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 $98.2 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 No. 144 (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 Company 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, we must estimate the undiscounted cash flows attributable to the asset. The Company'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 4(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 4(c) for further information on discontinued operations.

(e) Goodwill and Intangibles

The Company has approximately $19.7 million and $25.4 million of goodwill at December 31, 2008 and 2007, respectively. Goodwill created in the formation of the Partnership of $5.7 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 5 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 4(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 over the term of the related debt. 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 Company had imbalance payables of $7.1 million and $9.4 million at December 31, 2008 and 2007, respectively, which approximates the fair value for these imbalances. The Company 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 Company 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 Company has no current intention of discontinuing use of any significant assets.

(i) Revenue Recognition

The Company 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 Company 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. 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 energy trading activities related to "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, and schedules the transportation and assumes credit risk.

The Company 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. It generally determines 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 Company conducts "off-system" gas marketing operations as a service to producers on systems that the Company does not own. The Company refers to these activities as part of its energy trading activities. In some cases, the Company earns an agency fee from the producer for arranging the marketing of the producer's natural gas or NGLs. In other cases, the Company 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 statements of operations.

The Company 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 Company's future commitments and significantly reduce its risk to the movement in natural gas and NGL prices. However, the Company is subject to counterparty risk for both the physical and financial contracts. The Company's energy trading contracts qualify as derivatives, and accordingly, the Company 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 Company'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 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 Company records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges, net of income tax and minority interest, 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 Company to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited since the Company's customers represent a broad and diverse group of energy marketers and end users. In addition, the Company continually monitors and reviews credit exposure to its marketing counterparties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. The Company records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Company 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 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 Company. As the Company continues to grow and expand, this 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 Company'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 Company 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 Company 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, net of taxes and minority interest, of $0.2 million due to the reduction in previously recognized compensation costs associated with the estimation of forfeitures.

The Company and the Partnership each have similar unit or share-based payment plans for employees, which are described below. 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	$ 10,417	$ 7,448
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	$ 12,259	$ 8,579
Interest of non-controlling partners in share-based compensation	$ 4,014	$ 4,214	$ 2,857
Amount of related income tax benefit recognized in income	$ 2,685	$ 2,982	$ 2,121

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) Sales of Securities by Subsidiaries

The Company recognizes gains and losses in the consolidated statements of income resulting from subsidiary sales of additional equity interest, including exercises of stock options and CELP limited partnership units, to unrelated parties as discussed in Note 3(a).

(r) 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 Company 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's Emerging Issues Task Force ("EITF") reached a consensus on EITF 06-11 *"Accounting for Income Tax Benefits of Dividends on Share Based Payment Awards"*. The tax benefit received on dividends associated with share-based awards that are charged to retained earnings should be recorded in additional paid-in-capital ("APIC") and included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. The consensus is effective for the tax benefits of dividends declared in fiscal years beginning after December 15, 2007. The Company has evaluated the impact of the EITF and determined we will not recognize any tax benefit or a related credit to additional paid in capital for dividends on restricted stock charged to retained earnings. The tax benefit and credit to the APIC pool will be recognized when the tax deduction reduces income taxes payable after utilization of our net operating loss carry forward.

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 Company 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 Company will be to require expanded disclosure regarding derivative instruments.

(3) Public Offerings of Units by CELP and Certain Provisions of the Partnership Agreement

(a) Issuance of Common Units

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

On December 19, 2007, the Partnership 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, CEI 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. We own all 4,668,000 of the units that converted.

The 12,829,650 senior subordinated series C units of the Partnership issued June 29, 2006, also converted into common units representing limited partner interests of the Partnership effective February 16, 2008. The Company owns 6,414,830 of the senior subordinated series C units that converted to common 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. The Partnership 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 units for the quarter ending December 31, 2008, therefore 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 ending 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 its general partner is entitled to 13% of amounts the Partnership distributes in excess of $0.25 per unit, 23% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48% of amounts the Partnership distributes in excess of $0.375 per unit. Incentive distributions totaling $30.8 million, $24.8 million and $20.4 million were earned by the Company 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.

See Note 7 for a description of the Partnership's credit facilities which restrict the Partnership's ability to make future distributions.

(e) Allocation of Partnership Income

Net income is allocated to Crosstex Energy GP, L.P., a wholly-owned subsidiary of the Company, as the Partnership's general partner in an amount equal to its incentive distributions as described in Note 3(d) above. The general partner's share of the Partnership's net income is reduced by stock-based compensation expense attributed to the Company's stock options and restricted stock awarded to officers and employees of the Partnership. The remaining net income after incentive distributions and Company-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units (excluding senior subordinated units), and the common units. The following table reflects the Company's general partner share of the Partnership's net income (in thousands):

	Year 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

The Company also owns limited partner common units, limited partner subordinated units and limited partner senior subordinated series C units in the Partnership. The Company's share of the Partnership's net income attributable to its limited partner common and subordinated units was a net income of $5.9 million for the year ended December 31, 2008 respectively and a net loss of $2.0 million and $7.4 million for the year ended December 31, 2007 and 2006, respectively.

(4) 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.

(b) 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 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 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 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 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.

(c) 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 and the Partnership recorded a $49.8 million pre-tax gain. The pre-tax gain was adjusted for minority interest of $32.4 million and taxes of approximately $6.4 million. This asset was previously presented in the Partnership's Treating segment.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

The consolidated balance sheets at December 31, 2008 and December 31, 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. Following are revenues, income from discontinued operations net of minority interest and taxes and gain on discontinued operations net of minority interest and taxes (in thousands):

	2008	2007	2006
Treating Revenues	$ 8,539	$ 11,343	$ 11,718
Income from discontinued operations net of minority interest and taxes	$ 1,266	$ 1,532	$ 1,970
Gain from discontinued operations net of minority interest and taxes	$ 10,964	$ —	$ —

(5) 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.

The Company recorded $0.8 million of goodwill at the date of Partnership formation and this $0.8 million additional goodwill was impaired at the corporate level bringing the total impaired goodwill for CEI to $5.7 million for the period ended December 31, 2008.

(6) 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 their 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 majority 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.

(7) 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 credit agreement is guaranteed by its 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 the credit facility to, among other things, (i) increase the maximum permitted leverage ratio the Partnership must maintain for the fiscal quarters ending December 31, 2008 through September 30, 2009, (ii) lower the minimum interest coverage ratio the Partnership must maintain for the fiscal quarter ending December 31, 2008 and each fiscal quarter thereafter, (iii) permit the Partnership to sell certain assets, (iv) increase the interest rate the Partnership pays on the obligations under the credit facility and (v) lowers the maximum permitted leverage ratio the Partnership must maintain if it 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 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 the Partnership's 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 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 we fail 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 outstanding amount of 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 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 the fiscal quarters ending March 31, 2011 thru March 31, 2012; and
- 4.25 to 1.00 for the fiscal quarters ending June 20, 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 quarter 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 quarters ending September 30, 2010 and December 31, 2010;
- 2.50 to 1.00 for any fiscal quarters ending March 31, 2011, and thereafter.

Under the Sixth Amendment, no quarterly distributions may be paid to unitholders of the Partnership unless the PIK notes have been repaid and if 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 unitholders from available cash as provided by the 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 the Partnership's forecasted leverage ratios for 2009 and the Partnership's near term ability to refinance its bank credit facility, it does not anticipate making quarterly distributions in 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 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 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 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 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 the Partnership 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 the Partnership's 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 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.

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) Principle 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 its 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 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 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 the 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 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 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 equity interests in substantially all of the Partnership's 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 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 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 Partnership's purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of its senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under the Partnership's 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.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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

(8) 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

(9) Income Taxes

The Company 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).

	2008	2007	2006
Current tax provision	$ 2,593	$ 711	$ (268)
Deferred tax provision	7,022	10,338	11,386
	$ 9,615	$ 11,049	$ 11,118

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

A reconciliation of the provision for income taxes is as follows (in thousands):

	2008	2007	2006
Federal income tax at statutory rate (35)%	$ 11,847	$ 8,129	$ 9,591
State income taxes, net	1,329	682	567
Tax basis adjustment in Partnership related to issuance of common units	(5,209)	2,118	1,151
Non-deductible expenses	510	144	88
Other	1,138	(24)	(279)
Tax provision	$ 9,615	$ 11,049	$ 11,118

The following table summarizes the components of the income tax provision (in thousands):

	Years Ended December 31,		
	2008	2007	2006
From continuing operations	$ 2,410	$ 10,147	$ 9.958
From discontinued operations	7,205	902	1,160
Total tax provision	$ 9,615	$ 11,049	$ 11,118

The principal components of the Company's net deferred tax liability are 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 — non-current	40,310	35,229
Investment in the Partnership	3,892	9,101
Other comprehensive income	—	3,009
Other	41	140
	44,284	47,483
Less: valuation allowance	(3,892)	(9,101)
	40,392	38,382
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets — current	(501)	(501)
Property, plant, equipment, and intangible assets — non-current	(121,457)	(109,820)
Other comprehensive income	(367)	—
Other	(524)	(121)
	(122,849)	(110,442)
Net deferred tax liability	$ (82,457)	$ (72,060)

At December 31, 2008, the Company had a net operating loss carryforward of approximately $108.6 million that expires from 2021 through 2028. The Company also has various state net operating loss carryforwards of approximately $46.4 million which will begin expiring in 2019. Management believes that it is more likely than not that the future results of operations will generate sufficient taxable income to utilize these net operating loss carryforwards before they expire. Although the Company has generated net operating losses in the past, the

Company expects to have future taxable income from its investment in the Partnership, generated by the remedial allocations of income among the unitholders and the income generated by operations.

Deferred tax liabilities relating to property, plant, equipment and intangible assets represent, primarily, the Company's share of the book basis in excess of tax basis for assets inside of the Partnership. The Company has also recorded a deferred tax asset in the amount of $3.9 million relating to the difference between its book and tax basis of its investment in the Partnership. Because the Company can only realize this deferred tax asset upon the liquidation of the Partnership and to the extent of capital gains, the Company has provided a full valuation allowance against this deferred tax asset. The deferred tax asset and the related valuation allowance decreased $6.1 million during the first quarter of 2008 due to the conversion of the Partnership's senior subordinated series C units to common units and increased $0.9 million during the second quarter for the issuance of Partnership common units for a net decrease of $5.2 million from 2007 to 2008.

Effective as of January 1, 2007, the Company is now subject to the franchise margin tax enacted by the state of Texas on May 1, 2006. The new tax law had a $0.6 million impact on the Company's net deferred tax liability.

The Company 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	569
Increases related to current year tax positions	451
Balance as of December 31, 2008	$ 1,020

Unrecognized tax benefits of $1.0 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 2001 through 2008 remain subject to examination by the Internal Revenue Service and applicable states.

(10) Retirement Plans

The Company sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The Partnership makes contributions at each compensation calculation period based on the annual discretionary contribution rate. Contributions to the plan for the years ended December 31, 2008, 2007 and 2006 were $3.4 million, $1.6 million and $1.1 million, respectively.

(11) Employee Incentive Plans

(a) Long-Term Incentive Plan

In December 2002, the Partnership 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 Partnership's board of directors. The units issued upon exercise or vesting are newly issued units.

(b) Partnership 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.

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 (market value at date of grant) of units vested 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) Partnership 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:

Crosstex Energy, L.P. Unit Options Granted:	Years Ended December 31, 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

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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 exceeds 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 exercised (market value in excess of exercise price at date of exercise) and fair value (value per Black-Scholes option pricing model at date of grant) of units vested during the years ended December 31, 2008 and 2007 are provided below (in thousands):

Crosstex Energy, L.P. Unit Options:	Years Ended December 31, 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.

The Company'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

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

after three years of service. A summary of the restricted stock, which activity 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 reversed and is shown as a reduction to stock-based compensation expense and a reduction in the number of estimated performance shares outstanding of 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 (market value at date of grant) of shares vested during the years ended December 31, 2008 and 2007 are provided below (in thousands):

Crosstex Energy, Inc. Restricted Shares:	Years Ended December 31, 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 non-vested CEI restricted stock. The cost is expected to be recognized over a weighted average period of 2.4 years.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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 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.

A summary of the stock options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value (value per Black-Scholes option pricing model at date of grant) of units vested during the years ended December 31, 2008 and 2007 is provided below (in thousands):

Crosstex Energy, Inc. Stock Options:	Years Ended December 31, 2008	2007
Intrinsic value of stock options exercised	$ 1,089	$ 366
Fair value of shares 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 $15,931 of unrecognized compensation costs related to non-vested CEI stock options. The cost is expected to be recognized over a weighted average period of 0.7 years.

(12) Fair Value of Financial Instruments

The estimated fair value of the Company's financial instruments has been determined by the Company 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 Company could realize upon the sale or refinancing of such financial instruments (in thousands).

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

	December 31, 2008		December 31, 2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 13,959	$ 13,959	$ 7,853	$ 7,853
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, 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 Company'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 reflect to 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

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

* 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.

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.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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.

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, $1.1 million 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, $12.6 million 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 -Distribution of Assets for Cash

During 2008 we 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.

(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 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

Operating lease rental expense for 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 Company 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 Company are parties to employment contacts with the general partner of the Partnership. The employment agreements provide those senior managers with severance payments in certain circumstances and prohibit each such person from competing with the general partner of the Partnership 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 a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. 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.

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 Company does not expect to incur any material liability with these sites. In addition, the Partnership has disclosed possible Clean Air Act monitoring deficiencies it has discovered to the Louisiana Department of Environmental Quality and is working with the department to correct these deficiencies and to address modifications to facilities to bring them into compliance. The Company 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 estimated 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 Company does not expect to incur any material environmental liability associated with the Conroe site.

(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) Capital Stock

(a) Common Stock

On December 15, 2006, the Company made a three-for-one stock split in the form of a stock dividend.

In October 2006, the Company's stockholders approved an increase in the number of authorized shares of capital stock from 20 million shares, consisting of 19 million shares of common stock and 1 million shares of preferred stock, to 150 million shares, consisting of 140 million shares of common stock and 10 million shares of preferred stock.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

(b) Sale of Capital Stock

On June 29, 2006, the Company issued 7,650,780 shares of common stock in a private placement for total net proceeds of $179.9 million. Lubar Equity Fund, LLC, an affiliate of one of the Company's directors, purchased 468,210 of the shares at a purchase price of $25.633 per share and unrelated third-parties purchased 7,182,570 shares at a purchase price of $23.39. The Company used the proceeds of the stock issuance to purchase $180.0 million of senior subordinated series C units representing limited partner interests of the Partnership.

(c) Earnings per Share and Anti-Dilutive Computations

Basic earnings per common share was computed by dividing net income by the weighted-average number of common shares outstanding for the periods presented. The computation of diluted earnings per common share further assumes the dilutive effect of common share options and restricted shares.

In December 2006, the Company effected a three-for-one stock split. In conjunction with the Company's initial public offering in January 2004, the Company effected a two-for-one split. All share amounts for prior periods presented herein have been restated to reflect these stock splits.

The following are the share amounts used to compute the basic and diluted earnings per share for the years ended December 31, 2008, 2007 and 2006 (in thousands):

	Years Ended December 31,		
	2008	2007	2006
Basic shares:			
Weighted average common shares outstanding	46,298	45,988	42,168
Dilutive shares:			
Weighted average common shares outstanding	46,298	45,988	42,168
Dilutive effect of restricted shares	248	537	410
Dilutive effect of exercise of options	43	82	88
Dilutive shares	46,589	46,607	42,666

(18) Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Company's reportable segments consist of Midstream and Treating. The Midstream division consists of the Company's natural gas gathering and transmission operations and includes the south Louisiana processing and liquids assets, the gathering 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 Company'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 though 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 Company evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general corporate expenses associated with managing the operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt refinancing costs. Intersegment sales are at cost.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

Summarized financial information concerning the Company's reportable segments is shown in the following table. There are no other significant non-cash items.

Year Ended December 31, 2008:	Midstream	Treating	Corporate	Totals
		(In thousands)		
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	(148,906)	(27,517)	7,367	(169,056)
Segment profit	$ 221,882	$ 30,224	$ —	$ 252,106
Gain (loss) on derivatives	$ 12,203	$ —	$ —	$ 12,203
Impairments	$ 20,365	$ 1,063	$ 9,812	$ 31,240
Depreciation and amortization	$ (112,898)	$ (12,484)	$ (5,936)	$ (131,318)
Capital expenditures (excluding acquisitions)	$ 224,032	$ 32,299	$ 11,431	$ 267,762
Identifiable assets	$ 2,304,889	$ 200,114	$ 41,740	$ 2,546,743
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	(109,910)	(20,218)	4,944	(125,184)
Segment profit	$ 216,572	$ 30,516	$ —	$ 247,088
Gain (loss) on derivatives	$ 6,628	$ —	$ —	$ 6,628
Impairments	$ —	$ —	$ —	$ —
Depreciation and amortization	$ (89,621)	$ (12,327)	$ (4,737)	$ (106,685)
Capital expenditures (excluding acquisitions)	$ 371,120	$ 25,085	$ 5,192	$ 401,397
Identifiable assets	$ 2,339,326	$ 214,481	$ 49,022	$ 2,602,829
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	(83,400)	(17,851)	2,412	(98,839)
Segment profit	$ 134,776	$ 27,193	$ —	$ 161,969
Gain (loss) on derivatives	$ 1,591	$ —	$ —	$ 1,591
Impairments	$ —	$ —	$ —	$ —
Depreciation and amortization	$ (63,409)	$ (13,587)	$ (3,583)	$ (80,579)
Capital expenditures (excluding acquisitions)	$ 294,597	$ 31,463	$ 8,184	$ 334,244
Identifiable assets	$ 1,962,543	$ 203,528	$ 40,627	$ 2,206,698

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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

	Years Ended December 31, 2008	2007	2006
Segment profits	$ 252,106	$ 247,088	$ 161,969
General and administrative expenses	(74,518)	(64,304)	(47,707)
Gain on derivatives	12,203	6,628	1,591
Gain on sale of property	1,519	1,667	2,108
Depreciation and amortization	(131,318)	(106,685)	(80,579)
Impairments	(31,240)	—	—
Operating income	$ 28,752	$ 84,394	$ 37,382

(19) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per share amount)				
2008:					
Revenues	$ 1,266,720	$ 1,540,608	$ 1,330,610	$ 769,111	$ 4,907,049
Operating income (loss)	23,124	24,394	15,812	(34,578)	28,752
Income from discontinued operations — net of tax and net of minority interest	333	324	294	11,279	12,230
Net income (loss)	10,706	17,452	540	(4,465)	24,233
Basic earnings (loss) per common share	$ 0.23	$ 0.38	$ 0.01	$ (0.10)	$ 0.52
Diluted earnings (loss) per common share	$ 0.23	$ 0.37	$ 0.01	$ (0.10)	$ 0.52
2007:					
Revenues	$ 824,028	$ 999,113	$ 940,392	$ 1,085,555	$ 3,849,088
Operating income	10,271	18,635	21,164	34,324	84,394
Income from discontinued operations — net of tax and net of minority interest	341	378	378	435	1,532
Net income	74	2,193	2,181	7,728	12,176
Basic earnings per common share	$ 0.00	$ 0.05	$ 0.05	$ 0.17	$ 0.26
Diluted earnings per common share	$ 0.00	$ 0.05	$ 0.05	$ 0.17	$ 0.26

SCHEDULE I

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12,323	$ 7,712
Prepaid expenses and other	463	36
Total current assets	12,786	7,748
Investment in the Partnership	276,221	301,852
Total assets	$ 289,007	$ 309,600
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Payable to the Partnership	$ 110	$ 37
Other accrued liabilities	197	152
Total current liabilities	307	189
Deferred tax liability	73,271	63,045
Stockholders' equity:		
Common stock	464	463
Additional paid-in capital	268,988	267,859
Retained earnings	(54,693)	(16,878)
Accumulated other comprehensive income	670	(5,078)
Total stockholders' equity	215,429	246,366
Total liabilities and stockholders' equity	$ 289,007	$ 309,600

See "Notes to Consolidated Financial Statements" of Crosstex Energy, Inc. included in this report.

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2008	2007	2006
	(In thousands except share data)		
Operating income and expenses:			
Income from investment in the Partnership	$ 8,238	$ 15,670	$ 6,354
Income (loss) from investment in subsidiary	(139)	(35)	1,538
General and administrative expense	(3,429)	(2,776)	(2,014)
Impairment of goodwill	(804)	—	—
Operating income	3,866	12,859	5,878
Other income (expense):			
Interest and other income	238	410	378
Income from continuing operations before gain on issuance of units by the Partnership and income taxes	4,104	13,269	6,256
Gain on issuance of units in the Partnership	14,748	7,461	18,955
Income tax provision expense	(6,849)	(10,086)	(10,896)
Net income from continuing operations before discontinued operations and cumulative effect of change in accounting principle	12,003	10,644	14,315
Discontinued operations:			
Income from discontinued operations from investment in the Partnership-net of tax and net of minority interest	1,266	1,532	1,970
Gain on sale of discontinued operations from investment in the Partnership-net of tax and net of minority interest	10,964	—	—
Discontinued operations-net of tax and net of minority interest	12,230	1,532	1,970
Net income before cumulative effect of change in accounting principle	24,233	12,176	16,285
Cumulative effect of change in accounting principle from investment in the Partnership	—	—	170
Net income	$ 24,233	$ 12,176	$ 16,455
Net income before cumulative effect of change in accounting principle per common share:			
Basic and diluted	$ 0.52	$ 0.26	$ 0.39
Cumulative effect of change in accounting principle per common share:			
Basic and diluted	—	—	—
Net income per common share:			
Basic and diluted	$ 0.52	$ 0.26	$ 0.39
Weighted average common shares outstanding:			
Basic	46,298	45,988	42,168
Diluted	46,589	46,607	42,666

See "Notes to Consolidated Financial Statements" of Crosstex Energy, Inc. included in this report.

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2008	2007	2006
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 24,233	$ 12,176	$ 16,455
Adjustments to reconcile net income (loss) to net cash flow provided by (used in) operating activities:			
Income from investment in the Partnership, including discontinued operations	(20,428)	(17,202)	(8,324)
(Income) loss from investment in subsidiary	139	35	(1,538)
Impairment	804	—	—
Deferred taxes	6,849	10,086	10,896
Stock-based compensation	36	(25)	22
Gain on issuance of units in the Partnership	(14,748)	(7,461)	(18,955)
Cumulative effect of change in accounting principle from investment in the Partnership	—	—	(170)
Changes in assets and liabilities:			
Accounts receivable, prepaid expenses and other	(467)	68	(13)
Accounts payable and other accrued liabilities	118	116	(153)
Net cash provided by (used in) operating activities	(3,464)	(2,207)	(1,780)
Cash flows from investing activities:			
Investment in the Partnership	(2,193)	(4,014)	(189,407)
Distributions from the Partnership	76,026	47,565	41,711
Dividends from subsidiary	—	—	2,610
Contributions to subsidiary	(139)	(35)	—
Net cash provided by (used in) investing activities	73,694	43,516	(145,086)
Cash flows from financing activities:			
Proceeds from sale of common and preferred stock	—	—	179,720
Proceeds from exercise of common stock options	244	98	126
Conversion of restricted stock, net of shares withheld for taxes	(3,815)	(919)	—
Common dividends paid	(62,048)	(42,588)	(34,667)
Net cash provided by (used in) financing activities	(65,619)	(43,409)	145,179
Net increase (decrease) in cash	4,611	(2,100)	(1,687)
Cash, beginning of year	7,712	9,812	11,499
Cash, end of year	$ 12,323	$ 7,712	$ 9,812

See “Notes to Consolidated Financial Statements” of Crosstex Energy, Inc. included in this report.

SCHEDULE II

CROSSTEX ENERGY, INC.
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	—	Amended and Restated Certificate of Incorporation of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006).
3.2	—	Third Amended and Restated Bylaws of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated March 22, 2006, filed with the Commission on March 28, 2006).
3.3	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.4	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
3.5	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.6	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008).
3.7	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference from Exhibit 3.3 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.9	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.10	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference from Exhibit 3.6 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.11	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference from Exhibit 3.7 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.12	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference from Exhibit 3.8 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
4.1	—	Specimen Certificate representing shares of common stock (incorporated by reference from Exhibit 4.1 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
4.2	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy, Inc., Chieftain Capital Management, Inc., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LB I Group Inc., Lubar Equity Fund, LLC and Tortoise North American Energy Corp. (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).
10.1	—	Omnibus Agreement dated December 17, 2002, among Crosstex Energy, Inc. and certain other parties (incorporated by reference from Exhibit 10.5 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.2†	—	Form of Indemnity Agreement (incorporated by reference from Exhibit 10.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.3†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan dated July 12, 2002 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).

Number		Description
10.4†	—	Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.5	—	Agreement Regarding 2003 Registration Statement and Waiver and Termination of Stockholders' Agreement, dated October 27, 2003 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.6†	—	Crosstex Energy, Inc. Amended and Restated Long-Term Incentive Plan effective as of September 6, 2006 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006).
10.7	—	Registration Rights Agreement, dated December 31, 2003 (incorporated by reference from Exhibit 10.6 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003, file No. 000-50536).
10.8	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.9	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).
10.10	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.11	—	Third Amendment to Fourth Amended and Restated Credit Agreement, effective as of March 28, 2007, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.12	—	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 Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008).
10.13	—	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 (incorporated by reference to Exhibit 10.6 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008).
10.14	—	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 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated September 19, 2007, filed with the Commission on September 24, 2007).
10.15	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
10.16	—	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 to Crosstex Energy, L.P.'s Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.17	—	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 Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2008).

Table of Contents

Number		Description
10.18	—	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 (incorporated by reference to Exhibit 10.11 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2008).
10.19	—	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 Crosstex Energy, L.P.'s Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.20	—	Stock Purchase Agreement, dated as of May 16, 2006, by and among Crosstex Energy, Inc. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated May 16, 2006, filed with the Commission on May 17, 2006).
10.21	—	Senior Subordinated Series D Unit Purchase Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. an deach of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
10.22	—	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 Crosstex Energy, L.P.'s Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
10.23†	—	Form of Performance Share Agreement (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007).
10.24†	—	Form of Performance Unit Agreement (incorporated by reference to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007).
10.25†	—	Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.26	—	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., LB I Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.27	—	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 Crosstex Energy, L.P.'s Form 8-K dated April 9, 2008).
21.1*	—	List of Subsidiaries.
23.1*	—	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.

* Filed herewith.

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

Exhibit 21.1

LIST OF SUBSIDIARIES

Name of Subsidiary	State of Organization
Crosstex Energy, L.P.	Delaware
Crosstex Energy GP, LLC	Delaware
Crosstex Energy GP, LP	Delaware
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 Processing Services, LLC	Delaware
Crosstex Pelican, 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 Board of Directors and Stockholders of
Crosstex Energy, Inc.

We consent to the incorporation by reference in the registration statements Nos. 333-134713 and 333-136734 on Forms S-3 and registration statements Nos. 333-114014 and 333-141024 on Forms S-8 of Crosstex Energy, Inc. of our reports dated March 2, 2009, with respect to the consolidated balance sheets of Crosstex Energy, Inc. as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in stockholders' 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, Inc.

/s/ KPMG LLP

Dallas, Texas
March 2, 2009

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy, Inc., certify that:

1. I have reviewed this annual report on Form 10-K of Crosstex Energy, Inc.;

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, Inc., certify that:

1. I have reviewed this annual report on Form 10-K of Crosstex Energy, Inc.;

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, Inc. (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, Inc., and William W. Davis, Chief Financial Officer of Crosstex Energy, Inc., 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.

Date: March 2, 2009

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

Date: March 2, 2009

/s/ WILLIAM W. DAVIS
William W. Davis
Executive Vice President and
Chief Financial Officer

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.