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, 2009

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________________

Commission file number: 000-50067

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $70,576,421 on June 30, 2009, based on $3.11 per unit, the closing price of the Common Units as reported on the NASDAQ Global Select Market on such date.

At February 16, 2010, there were 49,691,715 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

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DESCRIPTION

CROSSTEX ENERGY, L.P.

PART I

Item 1. *Business*

General

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

We are an independent midstream energy company engaged in the gathering, transmission, processing and marketing of natural gas and natural gas liquids, or NGLs. We connect the wells of natural gas producers in our market areas to our gathering systems, process natural gas for the removal of NGLs, fractionate NGLs into purity products and market those products for a fee, transport natural gas and ultimately provide natural gas to a variety of markets. We purchase natural gas from natural gas producers and other supply sources and sell that natural gas to utilities, industrial consumers, other marketers and pipelines. We operate processing plants that process gas transported to the plants by major interstate pipelines or from our own gathering systems under a variety of fee arrangements. In addition, we purchase natural gas from producers not connected to our gathering systems for resale and sell natural gas on behalf of producers for a fee.

Our general partner interest is held by Crosstex Energy GP, L.P., a Delaware limited partnership. Crosstex Energy GP, LLC, a Delaware limited liability company, is Crosstex Energy GP, L.P.'s general partner. Crosstex Energy GP, LLC manages our operations and activities and employs our officers. Crosstex Energy GP, L.P. and Crosstex Energy GP, LLC are wholly owned subsidiaries of Crosstex Energy, Inc., or CEI. Crosstex Energy, Inc.'s shares are listed on the Nasdaq Global Select Market under the symbol "XTXI."

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

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

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

Our Operations

We focus on the gathering, processing, transmission and marketing of natural gas and NGLs. Our assets are located in two primary regions: north Texas and Louisiana. Our combined midstream assets consist of over 3,300 miles of natural gas gathering and transmission pipelines, nine natural gas processing plants and three fractionators. Our gathering systems consist of a network of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. Our processing plants remove NGLs from a natural gas stream and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso- and normal butanes and natural gasoline.

Our assets include the following:

- *North Texas Assets.* Our North Texas Assets are comprised of gathering, processing and transmission assets serving producers active in the Barnett Shale. Our gathering systems in north Texas consist of approximately 600 miles of gathering lines with total capacity of approximately 1,100 MMcf/d and total throughput was approximately 793,000 MMBtu/d for the year ended December 31, 2009. Our processing facilities in north Texas include three gas processing plants with a total processing capacity of 280 MMcf/d. Total processing throughput averaged 219,000 MMBtu/d for the year ended December 31, 2009. Our transmission asset consists of a 140-mile pipeline from an area near Fort Worth, Texas to a point near Paris, Texas and related facilities. The capacity on the North Texas Pipeline, or NTP, is 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, Gulf Crossing and other markets. For the year ended December 31, 2009, the total throughput on the NTP was approximately 318,000 MMBtu/d.

- *Crosstex LIG System.* The Crosstex LIG system is one of the largest intrastate pipeline systems in Louisiana, consisting of approximately 2,100 miles of gathering and transmission pipeline, with an average total throughput of approximately 900,000 MMBtu/d for the year ended December 31, 2009. The system also includes two operating, on-system processing plants, our Plaquemine and Gibson plants, with an average throughput of approximately 269,000 MMBtu/d for the year ended December 31, 2009. The system has access to both rich and lean gas supplies. These supplies reach from the Haynesville Shale in north Louisiana to new onshore production in south central and southeast Louisiana. Crosstex 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.

- *South Louisiana Processing and NGL Assets.* Our south Louisiana natural gas processing and liquids assets include a total of 2.0 Bcf/d of processing capacity, 66,000 Bbls/d of fractionation capacity, 2.4 million barrels of underground storage and approximately 400 miles of liquids transport lines. The assets include the Eunice processing plant and fractionation facility; the Pelican, Sabine and Blue Water processing plants; the Riverside fractionation plant; the Napoleonville storage facility; the Cajun Sibon pipeline system and the Intracoastal Pipeline. Total processing throughput averaged 856,000 MMBtu/d during December 2009. The Eunice plant is connected to onshore gas supply, as well as continental shelf and deepwater gas production. The Pelican and Sabine plants are connected with continental shelf and deepwater gas. The various plants have downstream connections to the ANR Pipeline, Florida Gas Transmission, Texas Gas Transmission, Tennessee Gas Pipeline and Transco.

Our Business Strategy

From our inception in 2002 until the second half of 2008, our long-term strategy had 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 volatility in the commodity and capital markets over the last 18 months and other events, including the substantial decline in commodity prices, we adjusted our business strategy in the fourth quarter 2008 and in 2009 to focus on maximizing our liquidity, improving our balance sheet through debt reduction and other methods, maintaining a stable asset base, improving the profitability of our assets by increasing their utilization while controlling costs and reducing our capital expenditures. Consistent with this strategy, we divested non-core assets since October 2008 for aggregate sale proceeds of $618.7 million and substantially reduced our outstanding debt. During 2010 we plan to continue our focus on (i) improving existing system profitability, (ii) continuing to improve our balance sheet and financial flexibility and (iii) pursuing strategic acquisitions and undertaking selective construction and expansion opportunities. Key elements of our strategy will include the following:

- *Improve existing system profitability.* We intend to operate our existing asset base to enhance profitability by continuing our initiatives to maximize utilization by improving operations, reducing operating costs and renegotiating contracts, when appropriate, to improve our economics. We have a solid base of assets 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. We market services directly to both producers and end users in order to connect new supplies of natural gas, contract new end user deliveries, improve margins and manage operations to fully utilize our systems' capacities. As part of this process, we focus on providing a full range of services to producers and end users, including supply aggregation and transportation and hedging, which we believe provides us with a competitive advantage when we compete for sources of natural gas supply.

- *Continue to improve our balance sheet and financial flexibility.* We intend to continue to improve our balance sheet and financial flexibility. We have established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA (earnings before interest, income taxes, depreciation and amortization, non-cash mark-to-market items and other miscellaneous non-cash items) of less than 4.0 to 1.0, and we do not currently expect to resume cash distributions on our outstanding units until we achieve such a ratio of less than 4.5 to 1.0 (pro forma for any distribution). In addition, any decision to resume cash distributions on our units and the amount of any such distributions would consider maintaining sufficient cash flow in excess of the distribution to continue to move towards lower leverage levels. We will also consider general economic conditions and our outlook for our business as we determine to pay any distribution. Our 2010 capital expenditure budget includes approximately $25.0 million of identified growth projects, and we expect to fund such expenditures with internally generated cash flow, with any excess cash flow applied towards debt, working capital or new projects. We will also consider the use of alternative financing strategies such as entering into joint venture arrangements. As of February 12, 2010, after our repayment of existing debt and borrowings under new debt agreements in January and early February 2010 discussed under "Recent Developments," we have approximately $193.1 million of available capacity for additional borrowings and potential letters of credit under our new credit facility. We believe that availability under our new credit facility, our ability to issue additional partnership units and enter into strategic joint venture arrangements should provide us with the financial flexibility to facilitate the execution of our business strategy.

- *Pursue strategic acquisitions and undertake selective construction and expansion opportunities ("organic growth").*

  - We intend to use our acquisition and integration experience to continue to make strategic acquisitions of assets that offer the opportunity for operational efficiencies and the potential for increased utilization and expansion of the acquired asset. We pursue acquisitions that we believe will add to existing core areas in order to capitalize on our existing infrastructure, personnel and producer and consumer relationships. We also examine opportunities to establish positions in new areas in regions with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas, primarily through the acquisition or development of key assets that will serve as a platform for further growth.

  - We also intend to leverage our existing infrastructure and producer and customer relationships by expanding existing systems to meet new or increased demand for our gathering, transmission, processing and marketing services. Substantially all of our capital projects during 2009 and our planned projects for 2010 target these types of opportunities.

- We will consider the construction of facilities and systems in new areas in regions with significant natural gas reserves and high levels of drilling activity or with growing demand for natural gas that lack midstream infrastructure to process and/or transport the natural gas. We believe our existing infrastructure and construction experience provide us with a competitive advantage for such expansion opportunities. For example:

  - We established a new core area through the acquisition of LIG Pipeline Company and subsidiaries, which we collectively referred to as Crosstex LIG, in 2004, thereby acquiring one of the largest intrastate pipeline systems in Louisiana. As a result of this acquisition, in 2006 and 2007 we had the opportunity to expand the system in north Louisiana in response to increasing production from the Cotton Valley formation, from a capacity of approximately 40 MMcf/d to approximately 275 MMcf/d. We then further expanded the system in north Louisiana during 2008 and 2009, increasing its capacity to 410 MMcf/d as of December 31, 2009 to take advantage of the increasing production and producer needs in the Haynesville Shale.

  - In 2006, we established a new core area in north Texas by adding the natural gas gathering pipeline systems and related facilities acquired from Chief Holdings LLC, or Chief, to our NTP, and other operations in the Barnett Shale area. Immediately prior to the acquisition, we had completed construction on our NTP. Since our 2006 acquisition, we have expanded our gathering system in north Texas and connected in excess of 500 new wells and significantly increased acreage dedicated to our systems. We have also constructed three gas processing plants with total processing capacity in the Barnett Shale of 280 MMcf/d.

  - In 2005, we acquired the south Louisiana processing business from El Paso Corporation, which included a lease of the Eunice NGL processing plant and fractionation facility. In October 2009, we acquired the Eunice NGL processing plant and fractionation facility, which will eliminate $12.2 million per year in lease expense and provide opportunities for optimization of the facility. In December 2009, we acquired the Intracoastal Pipeline, which we were using under a lease arrangement and which is integrated with our NGL system in south Louisiana. Not only will the acquisition of the Intracoastal Pipeline eliminate lease expense, but at the time of the acquisition we also received additional dedications of liquids volumes into our systems from another operator in the area.

Recent Developments

In the fourth quarter of 2008, we adjusted our business strategy to focus on maximizing our liquidity, reducing debt, maintaining a stable asset base, improving the profitability of our assets by increasing their utilization while controlling costs and reducing our capital expenditures. We are successfully executing our plan as highlighted by the following accomplishments:

- *Sold Non-Core Assets.* We sold $618.7 million of non-core assets and repaid approximately $500.0 million in long-term indebtedness from the sales proceeds over the last 15 months. In November 2008, we sold our 12.4% interest in the Seminole gas processing plant for $85.0 million. In the first quarter of 2009, we sold our Arkoma system for approximately $10.7 million. In August 2009, we sold our midstream assets in Alabama, Mississippi and south Texas for approximately $217.6 million. In addition, in October 2009, we sold our natural gas treating business for $265.4 million. We also sold our east Texas midstream assets on January 15, 2010 for $40.0 million.

- *Reduced Capital Expenditures.* We reduced our capital expenditures from over $275.6 million in 2008 to $101.4 million in 2009 and focused our capital projects on lower risk projects with higher expected returns.

- *Reduced Operating and General and Administrative Expenses*. We reduced our operating expenses from continuing operations to $110.4 million for the year ended December 31, 2009 from $125.8 million for the year ended December 31, 2008 and our general and administrative expenses from continuing operations to $59.9 million for the year ended December 31, 2009 from $68.9 million for the year ended December 31, 2008 by reducing staffing and controlling costs. General and administrative expenses for the year ended December 31, 2009 also include non-recurring costs totaling $4.4 million associated with severance payments, lease termination costs and bad debt expense due to the SemStream, L.P. bankruptcy.

- *Acquired Certain Assets in Our Core Areas.* We acquired the Eunice NGL processing plant and fractionation facility in October 2009 for $23.5 million in cash and the assumption of $18.1 million in debt. We originally acquired the contract rights associated with the Eunice plant as part of the south Louisiana acquisition in November 2005 and operated and managed the plant under an operating lease with an unaffiliated third party prior to the recent acquisition. This acquisition will eliminate lease obligations of $12.2 million per year. We also acquired the Intracoastal Pipeline located in southern Louisiana for approximately $10.3 million in December 2009. Both of these acquisitions were designed to enhance our NGL business.

- *Sale of Preferred Units.* On January 19, 2010, we issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions. The 14,705,882 preferred units are convertible at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. We have the right to force conversion of the preferred units after three years, subject to certain conditions. The preferred units are not redeemable but will pay a quarterly distribution that will be the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if we pay a cash distribution on common units.

- *Issuance of Senior Unsecured Notes*. On February 10, 2010, we issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the “notes” or “senior unsecured notes”) due 2018 at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under our new credit facility discussed below, were used to repay in full amounts outstanding under our existing bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with our existing credit facility. The notes are unsecured and unconditionally guaranteed on a senior basis by certain of our direct and indirect subsidiaries, including substantially all of our current subsidiaries. Interest payments will be paid semi-annually in arrears starting in August 2010. We have the option to redeem all or a portion of the notes at any time on or after February 15, 2014, at the specified redemption prices. Prior to February 15, 2014, we may redeem the notes, in whole or in part, at a “make-whole” redemption price. In addition, we may redeem up to 35% of the notes prior to February 15, 2013 with the cash proceeds from certain equity offerings.

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

Our Assets

North Texas Assets. Our NTP which commenced service in April 2006, consists of a 140-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas. The initial capacity of the NTP was approximately 250 MMcf/d. In 2007, we expanded the capacity on the NTP to a total of approximately 375 MMcf/d. The NTP connects production from the Barnett Shale to markets in north Texas and to markets accessed by the Natural Gas Pipeline Company, or NGPL, Kinder Morgan, Houston Pipeline, or HPL, Atmos, Gulf Crossing and other markets. For the year ended December 31, 2009, the total throughput on the NTP was approximately 318,000 MMBtu/d. The new interconnect with Gulf Crossing Pipeline, which commenced service in August 2009, provides our customers access to mid-west and east coast markets.

On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems included gathering pipelines, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that transaction, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas gathering system.

- *Gathering System.* Since the date of the acquisition through December 31, 2009, we have expanded our gathering system and connected in excess of 500 new wells to our north Texas gathering system and significantly increased the productive acreage dedicated to the system. As of December 31, 2009, total capacity on our north Texas gathering system was approximately 1,100 MMcf/d and total throughput averaged approximately 793,000 MMBtu/d for the year ended December 31, 2009.

- *Processing Facilities.* Since 2006, we have constructed three gas processing plants with a total processing capacity in the Barnett Shale of 280 MMcf/d, including our Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, our Azle plant, which is a 50 MMcf/d cryogenic processing plant and our Goforth plant, which is a 30 MMcf/d processing plant. Total processing throughput averaged 219,000 MMBtu/d for the year ended December 31, 2009.

We have budgeted approximately $15.0 million for continued development of our north Texas assets during 2010. These capital projects represent system expansions that are planned to handle volume growth as well as projects required pursuant to existing obligations with producers to connect new wells to our gathering systems in north Texas.

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

- *Crosstex LIG System.* The Crosstex LIG system is one of the largest intrastate pipeline systems in Louisiana, consisting of approximately 2,100 miles of gathering and transmission pipeline, with an average throughput of approximately 900,000 MMBtu/d for the year ended December 31, 2009. The system also includes two operating, on-system processing plants, our Plaquemine and Gibson plants, with an average throughput of 269,000 MMBtu/d for the year ended December 31, 2009. 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. Crosstex LIG has a variety of transportation and industrial sales customers, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans.

In 2007, we extended our Crosstex LIG system to the north to reach additional productive areas in the developing natural gas fields south of Shreveport, Louisiana, primarily in the Cotton Valley formation. This extension, referred to as the north Louisiana expansion, consists of 63 miles of 24” mainline with 9 miles of gathering lateral pipeline. Our north Louisiana expansion bisects the developing Haynesville Shale gas play in north Louisiana. The north Louisiana expansion was operating at near capacity during 2008 as the Haynesville gas was beginning to develop so we added 35 MMcf/d of capacity by adding compression during the third quarter of 2008 bringing the total capacity of the north Louisiana expansion to approximately 275 MMcf/d. We continued the expansion of our north Louisiana system during 2009 increasing capacity by 100 MMcf/d in July 2009 by adding compression. We increased our capacity by another 35 MMcf/d with a new interconnect into an interstate pipeline in December 2009 and bringing total capacity to 410 MMcf/d by the end of 2009. We have long-term firm transportation agreements subscribing to all of the incremental capacity added during 2009. In addition, we added compression during 2009 between the southern portion of our Crosstex LIG system and the northern expansion of our Crosstex LIG system, which increased the capacity to move gas from the north LIG system to our markets in the south to 145 MMcf/d. Interconnects on the north Louisiana expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission, Trunkline Gas and Tennessee Gas Pipeline.

We have budgeted approximately $10.0 million to add an additional 30 MMcf/d of fully contracted capacity in north Louisiana during 2010.

- *South Louisiana Processing and NGL Assets.* Natural gas processing capacity available to the Gulf Coast producers continues to exceed demand. During 2007, 2008, and 2009 we completed a number of operational changes at our Eunice facility and other plants to idle certain equipment, reduce operating expenses and reconfigure operations to manage the lower utilization. In addition, we have increased our focus on upstream markets and opportunities through integration of our Crosstex LIG system and south Louisiana processing assets to improve our overall performance. In 2008, our south Louisiana assets were negatively impacted by hurricanes Gustav and Ike, which came ashore in September 2008. Although we did not sustain substantial physical damage, several offshore platforms and pipelines owned by third parties transporting gas production to our Pelican, Eunice, Sabine Pass and Blue Water processing plants were damaged by the storms. Substantially all of the production from the pipeline systems supplying our plants was restored to pre-hurricane levels by September 2009. The south Louisiana processing assets include the following:

    - *Eunice Processing Plant and Fractionation Facility.* The Eunice processing plant is located in south central Louisiana, has a capacity of 750 MMcf/d and processed approximately 380,000 MMBtu/d during December 2009. 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. The Eunice fractionation facility, which was idled in August 2007, has a capacity of 36,000 barrels per day of liquid products. Beginning in August 2007, the liquids from the Eunice processing plant were transported through our Cajun Sibon pipeline system to our Riverside plant for fractionation. 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. We owned the contract rights associated with the Eunice plant and operated and managed the plant under an operating lease with an unaffiliated third party through October 2009. In October 2009, we acquired the Eunice plant for $23.5 million in cash and the assumption of $18.1 million in debt by buying out the operating lease, thereby eliminating $12.2 million of annual lease obligations.

    - *Pelican Processing Plant.* The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. During December 2009, the plant processed approximately 340,000 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 processing 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. The plant processed approximately 107,000 MMBtu/d during December 2009.

    - *Blue Water Gas Processing Plant.* We acquired a 23.85% interest in the Blue Water gas processing plant in the November 2005 El Paso acquisition and acquired an additional 35.42% interest in May 2006, at which time we became the operator of the plant. The plant has a net capacity to our interest of 186 MMcf/d. During 2008, TGP acquired Columbia Gulf Transmission's ownership share in the Blue Water pipeline. In January 2009, TGP reversed the flow of the gas on the pipeline thereby removing access to all the gas processed at our Blue Water plant from the Blue Water offshore system and the plant did not operate during the nine months ended September 30, 2009. In November 2009, the plant was restarted to process the reverse flow stream on TGP. The gas composition of the reverse TGP stream is leaner in NGL content, but may be profitable to process during periods of high fractionation spreads. The plant is expected to operate in this mode periodically as fractionation spread and volumes dictate. When we process the reverse stream, we earn all of the margin from processing the gas under a straddle agreement with TGP.

- *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 approximately 30,000 Bbls/d of liquids products and fractionates liquids delivered by the Cajun Sibon pipeline system from the Eunice, Pelican and Blue Water plants or by truck. The Riverside facility has above-ground storage capacity of approximately 102,000 barrels.

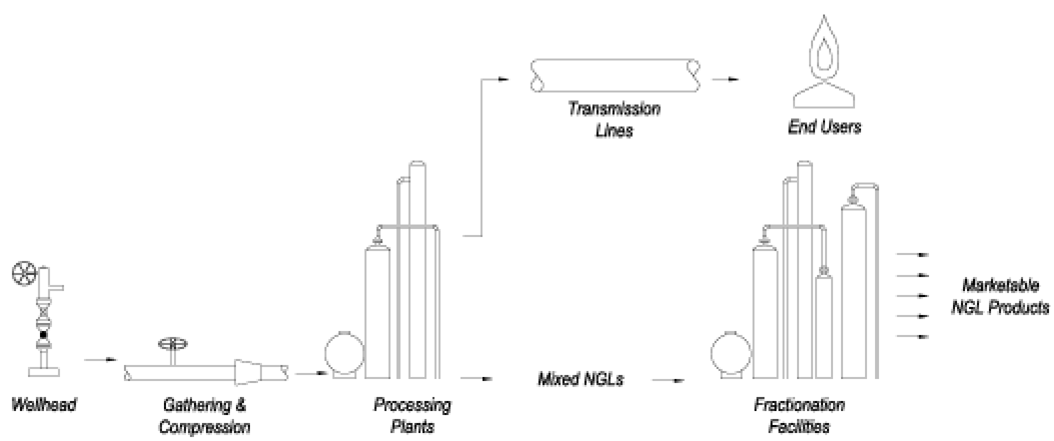
- *Napoleonville Storage Facility.* The Napoleonville NGL storage facility is connected to the Riverside facility and has a total capacity of approximately 2.4 million barrels of underground storage from two existing caverns. The caverns are currently operated in propane and butane service and space is sold to customers for a fee.

- *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 to third party fractionators when necessary. Alternate deliveries can be made to the Eunice fractionation facility when operational.

- *Intracoastal Pipeline.* In December 2009, we acquired the Intracoastal Pipeline from a subsidiary of Chevron Midstream Pipelines LLC. The pipeline consists of approximately 62 miles of six and eight inch pipeline and extends from Patterson to Henry in southern Louisiana. The pipeline connects our Pelican processing plant to the Cajun Sibon pipeline system and accesses other third party processing plants in the region. Prior to our acquisition, we utilized portions of the Intracoastal Pipeline under a long-term lease arrangement. This acquisition eliminates approximately $1.3 million of annual lease expense. We have also entered into an agreement to use the system to bring additional liquids into our NGL system.

Industry Overview

The following diagram illustrates the 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-user 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 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 may need to 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 facilities 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.

Balancing of Supply and Demand

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

Competition

The business of providing gathering, transmission, processing and marketing services for natural gas and NGLs is highly competitive. We face strong competition in obtaining natural gas supplies and in the marketing and transportation of natural gas and NGLs. Our competitors include major integrated oil companies, natural gas producers, interstate and intrastate pipelines and other natural gas gatherers and processors. Competition for natural gas supplies is primarily based on geographic location of facilities in relation to production or markets, the reputation, efficiency and reliability of the gatherer and the pricing arrangements offered by the gatherer. Many of our competitors offer more services or have greater financial resources and access to larger natural gas supplies than we do. Our competition differs in different geographic areas.

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

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

Natural Gas Supply

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

Credit Risk and Significant Customers

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

During the year ended December 31, 2009, we had one customer that accounted for approximately 12.2% of our consolidated revenues from continuing operations. While this customer represents a significant percentage of consolidated revenues, the loss of this customer would not have a material impact on our results of operations.

Regulation

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

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

While we do not own any interstate pipelines, we do transport gas in interstate commerce. The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC jurisdiction under Section 311 of the Natural Gas Policy Act, or NGPA. In addition, FERC has adopted, or is in the process of adopting, various regulations concerning natural gas market transparency that will apply to some of our pipeline operations. The maximum rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate", as defined in the NGPA. The rates are generally subject to review every three years by FERC or by an appropriate state agency. The inability to obtain approval of rates at acceptable levels could result in refund obligations, the inability to achieve adequate returns on investments in new facilities and the deterrence of future investment or growth of the regulated facilities.

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

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

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

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

Environmental Matters

General. Our operation of processing and fractionation plants, pipelines and associated facilities in connection with the gathering and processing of natural gas and the transportation, fractionation and storage of NGLs is subject to stringent and complex federal, state and local laws and regulations relating to release of hazardous substances or wastes into the environment or otherwise relating to protection of the environment. As with the industry generally, compliance with existing and anticipated environmental laws and regulations increases our overall costs of doing business, including costs of planning, constructing, and operating plants, pipelines, and other facilities. Included in our construction and operation costs are capital cost items necessary to maintain or upgrade equipment and facilities. Similar costs are likely upon changes in laws or regulations and upon any future acquisition of operating assets.

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

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

Hazardous Substance and Waste. To a large extent, the environmental laws and regulations affecting our 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 ordinary operations, we may generate wastes that may fall within the definition of a "hazardous substance." In addition, there are other laws and regulations that can create liability for releases of petroleum, natural gas or NGLs. Moreover, we may be responsible under CERCLA or other laws for all or part of the costs required to clean up sites at which such wastes have been disposed. We have not received any notification that we may be potentially responsible for cleanup costs under CERCLA or any analogous federal or state laws.

We also generate, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and/or comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. From time to time, the Environmental Protection Agency, or EPA, and state regulatory agencies have considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. Moreover, it is possible that some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly management and disposal requirements. Changes in applicable laws or regulations may result in an increase in our capital expenditures or plant operating expenses or otherwise impose limits or restrictions on our production and operations.

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

Air Emissions. Our current and future operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and impose various monitoring and reporting requirements. Pursuant to these laws and regulations, we may be required to obtain environmental agency pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and comply with the terms of air permits, which include various emission and operational limitations, or use specific emission control technologies to limit emissions. We likely will be required to incur certain capital expenditures in the future for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air-emission related issues. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties, and may result in the limitation or cessation of construction or operation of certain air emission sources. Although we can give no assurances, we believe such requirements will not have a material adverse effect on our financial condition or operating results, and the requirements are not expected to be more burdensome to us than any similarly situated company.

Air emissions associated with operations in the Barnett Shale area have come under recent scrutiny. In 2009, the Texas Commission on Environmental Quality (TCEQ) conducted comprehensive monitoring of air emissions in the Barnett Shale area, in response to public concerns about high concentrations of benzene in the air near drilling sites and natural gas processing facilities. A comprehensive report detailing the monitoring results and their potential health impacts is expected to be finalized in early 2010. Environmental groups have advocated increased regulation in the Barnett Shale area and these groups as well as at least one state representative have further advocated a moratorium on permits for new gas wells until TCEQ completes its analysis. Also, the EPA recently entered into a settlement that requires it to reevaluate regulations for the control of air emissions from natural gas production facilities. Changes in laws or regulations imposing emission limitations, pollution control technology requirements or other regulatory requirements or any restriction on permitting of natural gas production facilities in the Barnett Shale area could have an adverse effect on our business.

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. In addition, EPA is taking steps that would result in the regulation of greenhouse gases as pollutants under the federal Clean Air Act. Furthermore, in September 2009, EPA finalized regulations that require monitoring and reporting of greenhouse gas emissions on an annual basis, including extensive greenhouse gas monitoring and reporting requirements, beginning in 2010. Although the greenhouse gas reporting rule does not control greenhouse gas emission levels from any facilities, it will still cause us to incur monitoring and reporting costs for emissions that are subject to the rule. Some of our facilities include source categories that are subject to the greenhouse gas reporting requirements included in the final rule. However, EPA postponed a decision on proposed Subpart W to 40 CFR part 98, which would have applied to fugitive and vented methane emissions from the oil and gas sector, including natural gas transmission compression. The prospect remains that EPA will adopt regulations that require reporting of fugitive and vented methane emissions from the oil and gas industry, which will increase our monitoring and reporting costs. In December 2009, EPA also issued findings that greenhouse gases in the atmosphere endanger public health and welfare, and that emissions from mobile sources cause or contribute to greenhouse gases in the atmosphere. The endangerment findings will not immediately affect our operations, but standards eventually promulgated pursuant to these findings could affect our operations and ability to obtain air permits for new or modified facilities. Legislation and regulations relating to control or reporting of greenhouse gas emissions are also in various stages of discussions or implementation in about one-third of the states. Lawsuits have been filed seeking to force the federal government to regulate greenhouse gases emissions under the Clean Air Act and to require individual companies to reduce greenhouse gas emissions from their operations. These and other lawsuits may result in decisions by state and federal courts and agencies that could impact our operations and ability to obtain certifications and permits to construct future projects.

Passage of climate change legislation or other federal or state legislative or regulatory initiatives that regulate or restrict emissions of greenhouse gases in areas in which we conduct business could adversely affect the demand for the products we store, transport, and process, and depending on the particular program adopted could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and/or administer and manage a greenhouse gas emissions program. We may be unable to recover any such lost revenues or increased costs in the rates we charge our customers, and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or regulations. Reductions in our revenues or increases in our expenses as a result of climate control initiatives could have adverse effects on our business, financial position, results of operations and prospects.

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

It is customary to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is an important and commonly used process in the completion of wells by our customers, particularly in Barnett Shale and Haynesville Shale regions of our operations. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. In particular, the U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for our customers to perform hydraulic fracturing. Any increased federal, state or local regulation could reduce the volumes of natural gas that our customers move through our gathering systems which would materially adversely affect our revenues and results of operations.

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

Safety Regulations. Our pipelines are subject to regulation by the U.S. Department of Transportation under the Hazardous Liquid Pipeline Safety Act, as amended, or HLPSA, and the Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192, effective February 14, 2004 relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. The HLPSA covers crude oil, carbon dioxide, NGL and petroleum products pipelines and requires any entity which owns or operates pipeline facilities to comply with the regulations under the HLPSA, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. The Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192 (PIM) requires operators of gas transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. In addition, the Railroad Commission of Texas, or TRRC, regulates our pipelines in Texas under its own pipeline integrity management rules. The Texas rule includes certain transmission and gathering lines based upon pipeline diameter and operating pressures. We believe that our pipeline operations are in substantial compliance with applicable HLPSA and PIM requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, there can be no assurance that future compliance with the HLPSA or PIM requirements will not have a material adverse effect on our results of operations or financial positions.

Office Facilities

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

Employees

As of December 31, 2009, we (through our Operating Partnership) employed approximately 456 full-time employees. Approximately 244 of our employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. We are not party to any collective bargaining agreements, and we have not had any significant labor disputes in the past. We believe that we have good relations with our employees.

Item 1A. *Risk Factors*

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

Risks Inherent In Our Business

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

We are subject to significant risks due to fluctuations in commodity prices. We are directly exposed to these risks primarily in the gas processing component of our business. We are also indirectly exposed to commodity prices due to the negative impacts on production and the development of production of natural gas and NGLs connected to or near our assets and on our margins for transportation between certain market centers. A large percentage of our processing fees are realized under percent of liquids (POL) contracts that are directly impacted by the market price of NGLs. We also realize processing gross margins under processing margin (margin) contracts. These settlements are impacted by the relationship between NGL prices and the underlying natural gas prices, which is also referred to as the fractionation spread.

A significant volume of inlet gas at our south Louisiana and north Texas processing plants is settled under POL agreements. The POL fees are denominated in the form of a share of the liquids extracted and we are not responsible for the fuel or shrink associated with processing. Therefore, revenue under a POL agreement is directly impacted by NGL prices, and the decline of these prices in the second half of 2008 and early 2009 contributed to a significant decline in our gross margin from processing.

We have a number of contracts on our Plaquemine and Gibson processing plants that expose us to the fractionation spread. Under these margin contracts our gross margin is based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state ("shrink") and the cost of fuel to extract during processing. During the second half of 2008 and early 2009, 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. Such a decline may negatively impact our gross margin in the future if we have such declines again.

In the past, the prices of natural gas and NGLs have been extremely volatile and we expect this volatility to continue. For example, prices of oil, natural gas and NGLs in 2009 were below the market price realized throughout most of 2008. Crude oil prices (based on the New York Mercantile Exchange (the "NYMEX") futures daily close prices for the prompt month) improved during 2009 with prices ranging from a low of $33.98 per Bbl in February 2009 to a high of $81.37 per Bbl in October 2009. Weighted average NGL prices (based on the Oil Price Information Service (OPIS) Mt. Belvieu daily average spot liquids prices) have also improved with prices ranging from a low of $0.58 per gallon in March 2009 to a high of $1.21 per gallon in December 2009. Natural gas prices declined during 2009 with prices ranging from a high of $6.10 per MMBtu in January 2009 to a low of $1.85 per MMBtu in September 2009. Natural gas prices improved during the fourth quarter of 2009, with prices reaching a high of $6.00 per MMBtu in December 2009.

The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include the supply and demand for oil, natural gas and NGLs, which fluctuate 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;
- technology, including improved production techniques (particularly with respect to shale development);
- 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, including the regulation of "greenhouse gases."

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

Our substantial indebtedness could limit our flexibility and adversely affect our financial health.

We have a substantial amount of indebtedness. As of December 31, 2009, we had approximately $873.7 million of indebtedness outstanding. As of February 12, 2010, after repayment of existing debt with proceeds from the sale of preferred units together with proceeds from the issuance of our senior unsecured notes and borrowings under our new credit facility, we had approximately $790.6 million (including $15.2 million of original issue discount on the senior unsecured notes) of indebtedness outstanding, including $725.0 million of senior unsecured notes and $47.5 million of secured indebtedness outstanding under our new credit facility. We also had approximately $179.4 million of letters of credit outstanding under our old credit facility as of February 12, 2010 that were subsequently replaced by letters of credit under the new credit facility.

Our substantial indebtedness could limit our flexibility and adversely affect our financial health. For example, it could:

- make us more vulnerable to general adverse economic and industry conditions;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our indebtedness, thereby reducing the availability of our cash flow for operations and other purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- place us at a competitive disadvantage compared to competitors that may have proportionately less indebtedness.

In addition, our ability to make scheduled payments or to refinance our obligations depends on our successful financial and operating performance. We cannot assure you that our operating performance will generate sufficient cash flow or that our capital resources will be sufficient for payment of our indebtedness obligations in the future. Our financial and operating performance, cash flow and capital resources depend upon prevailing economic conditions and certain financial, business and other factors, many of which are beyond our control.

If our cash flow and capital resources are insufficient to fund our debt service obligations, we may be forced to sell material assets or operations, obtain additional capital or restructure our debt. In the event that we are required to dispose of material assets or operations or restructure our debt to meet our debt service and other obligations, we cannot assure you as to the terms of any such transaction or how quickly any such transaction could be completed, if at all.

We may not be able to obtain additional funding for future capital needs or to refinance our debt, either on acceptable terms or at all.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile, which has caused substantial contraction in the credit and capital markets. These conditions, along with significant write-offs in the financial services sector and current weak economic conditions, have made, and will likely continue to make, it difficult to obtain funding for our capital needs. As a result, 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. Due to these factors, we cannot be certain that new debt or equity financing will be available to us on acceptable terms or at all. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due. Without adequate funding, we may be unable to execute our growth strategy, complete future acquisitions or future construction projects or other capital expenditures, take advantage of other business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations. Further, our customers may increase collateral requirements from us, including letters of credit which reduce available borrowing capacity, or reduce the business they transact with us to reduce their credit exposure to us.

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

We operate in a capital-intensive industry and rely on our new credit facility to assist in financing a significant portion of our capital expenditures. Our ability to borrow under our new credit facility may be impaired. Specifically, we may be unable to obtain adequate funding under our new credit facility because:

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

If we are unable to access funds under our new credit facility, we will need to meet our capital requirements, including some of our short-term capital requirements, using other sources. Alternative sources of liquidity may not be available on acceptable terms, if at all. If the cash generated from our operations or the funds we are able to obtain under our new credit facility or other sources of liquidity are not sufficient to meet our capital requirements, then we may need to delay or abandon capital projects or other business opportunities, which could have a material adverse effect on our results of operations and financial condition.

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

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

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

Many of our customers finance their drilling activities through cash flow from operations, the incurrence of debt or the issuance of equity. During the last half of 2008 and during 2009, there was a significant decline in the credit markets and the availability of credit. 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 has resulted in lower volumes that we otherwise would have seen being transported on our pipeline and gathering systems and processing through our processing plants. We saw a decline in drilling activity by gas producers in our Barnett Shale area of operation in north Texas during the fourth quarter of 2008 and during 2009. A continued decline in drilling activity or low drilling activity could have a material adverse effect on our operations.

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

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

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

Our operations expose us to fluctuations in commodity prices, and our new credit facility exposes us to fluctuations in interest rates. We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions and interest rate swaps with financial institutions. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices and interest rates. As of December 31, 2009, we have hedged only portions of our variable-rate debt and expected natural gas supply, NGL production and natural gas requirements, and had direct interest rate and commodity price risk with respect to the unhedged portions. In addition, to the extent we hedge our commodity price and interest rate risks using swap instruments, we will forego the benefits of favorable changes in commodity prices or interest rates. In February 2010, we settled all of our interest rate swaps associated with our old credit facility when we repaid the debt outstanding under this facility.

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

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

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

We may not be successful in balancing our purchases and sales.

We are a party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In addition, a producer could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a consumer could purchase more or less than contracted volumes. Any of these actions could cause our purchases and sales not to be balanced. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

We make certain commitments to purchase natural gas in production areas based on production-area indices and to sell the natural gas into market areas based on market-area indices, pay the costs to transport the natural gas between the two points and capture the difference between the indices as margin. Changes in the index prices relative to each other (also referred to as basis spread) can significantly affect our margins or even result in losses. For example, we are a party to one contract where we buy gas on several different production-area indices on our NTP and sell the gas into a different market area index. For the fourth quarter of 2009, this imbalance resulted in a loss of approximately $1.8 million due to basis differentials between the various market prices.

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

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

In order to maintain or increase throughput levels in our natural gas gathering systems and asset utilization rates at our processing plants and to fulfill our current sales commitments, we must continually contract for new natural gas supplies. We may not be able to obtain additional contracts for natural gas supplies. The primary factors affecting our ability to connect new wells to our gathering facilities include our success in contracting for existing natural gas supplies that are not committed to other systems and the level of drilling activity near our gathering systems. Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. For example, as oil and natural gas prices decreased during the last half of 2008 and the first half of 2009, there was a corresponding decrease in drilling activity. Tax policy changes or additional regulatory restrictions on development could also have a negative impact on drilling activity, reducing supplies of natural gas available to our systems. We have no control over producers and depend on them to maintain sufficient levels of drilling activity. A material decrease in natural gas production or in the level of drilling activity in our principal geographic areas for a prolonged period, as a result of depressed commodity prices or otherwise, likely would have a material adverse effect on our results of operations and financial position.

We are vulnerable to operational, regulatory and other risks due to our concentration of assets in south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes.

Our operations and revenues will be significantly impacted by conditions in south Louisiana and the Gulf of Mexico because we have a significant portion of our assets located in south Louisiana and the Gulf of Mexico. In 2008, our business was negatively impacted by hurricanes Gustav and Ike, which came ashore in the Gulf Coast in September. These storms resulted in an adverse impact to our gross margins of approximately $22.9 million in the last half of 2008. Although we did not sustain substantial physical damage, several offshore production platforms and pipelines owned by third parties that transport gas production to our Pelican, Eunice, Sabine Pass and Blue Water processing plants in south Louisiana were damaged by the storms. Some of the repairs to these offshore facilities were completed during the fourth quarter of 2008, but gas production to our south Louisiana plants did not recover to pre-hurricane levels until September 2009.

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

- adverse weather conditions, including hurricanes and tropical storms;

- delays or decreases in production, the availability of equipment, facilities or services; and

- changes in the regulatory environment.

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

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

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

The U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells by our customers, particularly in Barnett Shale and Haynesville Shale regions of our operations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for our customers to perform hydraulic fracturing. Many producers make extensive use of hydraulic fracturing in the areas that we serve and any increased federal, state or local regulation could reduce the volumes of natural gas that they move through our gathering systems which would materially adversely affect our revenues and results of operations.

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

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

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

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

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

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

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

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

Additionally, our ability to grow our asset base in the near future through acquisitions may be limited due to our lack of access to capital markets.

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

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

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

The renewal or replacement of existing contracts with our customers at rates sufficient to maintain current revenues and cash flows depends on a number of factors beyond our control, including competition from other pipelines, and the price of, and demand for, natural gas in the markets we serve. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

In particular, our ability to renew or replace our existing contracts with industrial end-users and utilities impacts our profitability. For the year ended December 31, 2009, approximately 48.5% of our sales of gas that was transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price.

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

We derive a significant portion of our revenues from contracts with key customers. To the extent that these and other customers may reduce volumes of natural gas purchased or transported under existing contracts, we would be adversely affected unless we were able to make comparably profitable arrangements with other customers. Certain agreements with key customers provide for minimum volumes of natural gas or natural gas services that require the customer to transport, process or purchase until the expiration of the term of the applicable agreement, subject to certain force majeure provisions. Customers may default on their obligations to transport, process or purchase the minimum volumes of natural gas or natural gas services required under the applicable agreements.

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

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

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

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. We are not fully insured against all risks incident to our business. In accordance with typical industry practice, we do not have any property insurance on any of our underground pipeline systems that would cover damage to the pipelines. We are not insured against all environmental accidents that might occur, other than those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition.

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

Terrorist attacks or the threat of terrorist attacks cause instability in the global financial markets and other industries, including the energy industry. Infrastructure facilities, including pipelines, production facilities, and transmission and distribution facilities, could be direct targets, or indirect casualties, of an act of terror. Our insurance policies generally exclude acts of terrorism. Such insurance is not available at what we believe to be acceptable pricing levels.

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

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

The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC regulation under the Section 311 of the Natural Gas Policy Act. Under these regulations, we are required to justify our rates for interstate transportation service on a cost-of-service basis, every three years. Our intrastate natural gas pipeline operations are subject to regulation by various agencies of the states in which they are located. Should FERC or any of these state agencies determine that our rates for Section 311 transportation service or intrastate transportation service should be lowered, our business could be adversely affected.

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

The states in which we conduct operations administer federal pipeline safety standards under the Pipeline Safety Act of 1968. The "rural gathering exemption" under the Natural Gas Pipeline Safety Act of 1968 presently exempts substantial portions of our gathering facilities from jurisdiction under that statute, including those portions located outside of cities, towns, or any area designated as residential or commercial, such as a subdivision or shopping center. The "rural gathering exemption," however, may be restricted in the future, and it does not apply to our natural gas transmission pipelines. In response to recent pipeline accidents in other parts of the country, Congress and the Department of Transportation, or DOT, have passed or are considering heightened pipeline safety requirements.

Compliance with pipeline integrity regulations issued by the United States Department of Transportation in December 2003 or those issued by the TRRC could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations, adjusted to exclude costs associated with discontinued operations, were approximately at $1.1 million, $1.4 million, and $0.1 million for the years ended December 31, 2009, 2008, and 2007, respectively. We expect the costs for compliance with TRRC and DOT regulations to be approximately $3.7 million during 2010. If our pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then we may be required to repair or replace sections of such pipelines, the cost of which cannot be estimated at this time.

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

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

Many of the operations and activities of our gathering systems, processing plants, fractionators and other facilities are subject to significant federal, state and local environmental laws and regulations. The obligations imposed by these laws and regulations include obligations related to air emissions and discharge of pollutants from our facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these laws and 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 near our facilities or upon or through which our gathering systems traverse, 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 for releases of contaminants or for personal injury or property damage.

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

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental laws or regulations, including, for example, legislation being considered by the U.S. Congress relating to the control of greenhouse gas emissions or changes in existing environmental laws or regulations might adversely affect our products and activities, including processing, storage and transportation, as well as waste management and air emissions. Federal and state agencies could also impose additional safety requirements, any of which could affect our profitability. Changes in laws or regulations could also limit our production or the operation of our assets or adversely affect our ability to comply with applicable legal requirements or the demand for natural gas, which could adversely affect our business and our profitability.

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

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

Risk Inherent In An Investment In the Partnership

Crosstex Energy, Inc., or CEI, controls our general partner and owned a 25.0% limited partner interest in us as of January 31, 2010. Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor its own interests.

As of January 31, 2010, CEI indirectly owned an aggregate limited partner interest of approximately 25.0% in us. In addition, CEI owns and controls our general partner. Due to its control of our general partner and the size of its limited partner interest in us, CEI effectively controls all limited partnership decisions, including any decisions related to the removal of our general partner. Conflicts of interest may arise in the future between CEI and its affiliates, including our general partner, on the one hand, and our partnership, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates over our interests. These conflicts include, among others, the following situations:

Conflicts Relating to Control

- our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without these limitations, constitute breaches of fiduciary duty by our general partner;

- in resolving conflicts of interest, our general partner is allowed to take into account the interests of parties in addition to unitholders, which has the effect of limiting its fiduciary duties to the unitholders;

- our general partner's affiliates may engage in limited competition with us;

- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;

- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;

- in some instances our general partner may cause us to borrow funds from affiliates of the general partner or from third parties in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions; and

- our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution.

Conflicts Relating to Costs:

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

- our general partner determines which costs incurred by it and its affiliates are reimbursable by us; and

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

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

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

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The general partner generally may not be removed except upon the vote of the holders of 66 2/3% of the outstanding units voting together as a single class. Affiliates of the general partner controlled approximately 27.0% of all the units as of January 31, 2010.

In addition, unitholders' voting rights are further restricted by the partnership agreement. It provides that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of the general partner's general partner, cannot be voted on any matter. In addition, the partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

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

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

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

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

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

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

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

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

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

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

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. The issuance of additional limited partner interests will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

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

If at any time our general partner and its affiliates own more than 80.0% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. Our unitholders may also incur a tax liability upon a sale of their units.

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

Our unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right or the exercise of the right by our unitholders to remove or replace our general partner, to approve amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the "control" of our business, to the extent that a person who has transacted business with the partnership reasonably believes, based on our unitholders' conduct, that our unitholders are a general partner. Our general partner generally has unlimited liability for the obligations of the partnership, such as its debts and environmental liabilities, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of that section may be liable to the limited partnership for the amount of the distribution for a period of three years from the date of the distribution. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business.

Tax Risks to Our Unitholders

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

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

If we were treated as a corporation for federal income tax purposes, we would pay additional tax on our income at corporate rates of up to 35.0% (under the law as of the date of this report) and we would probably pay state income taxes as well. In addition, distributions to unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses, or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders and thus would likely result in a material reduction in the value of the common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, members of Congress have considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the legislation considered would not have appeared to affect our tax treatment, we are unable to predict whether any such change or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. At the state level, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 1.0% of our gross income apportioned to Texas in the prior year. If federal income tax or material amounts of additional state tax were to be imposed on us, the cash available for distribution to unitholders could be reduced and/or the value of an investment in our common units would be adversely impacted. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state, or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts will be decreased to reflect the impact of that law on us.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the costs of any contest could reduce the cash available for distribution to our unitholders.

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

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

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, they will be required to pay federal income taxes and, in some cases, state, local, and foreign income taxes on their share of our taxable income even if they do not receive cash distributions from us. Unitholders may not receive cash distributions equal to their share of our taxable income or even the tax liability that results from that income. We do not currently expect to pay a distribution until late 2010 or 2011.

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

Unitholders who sell common units will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions in excess of the total net taxable income allocated for a common unit, which decreased the tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the tax basis in that common unit, even if the price received is less than the original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to the unitholder due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, a unitholder who sells units may incur a tax liability in excess of the amount of cash received from the sale. As a result of the foregoing, unitholders who sell units may incur a tax liability in excess of the amount of cash they receive from the sale.

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

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

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

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

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

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder who has adopted a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder's taxable income for the year of termination. Our termination would cause us to be treated as a new partnership for tax purposes, and we could be subject to penalties if we were to fail to recognize and properly report on our tax return that a termination occurred.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. For example, members of Congress have been considering substantive changes to the definition of qualifying income and the treatment of certain types of income earned from profits interests in partnerships. While these specific proposals would not appear to affect our treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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

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

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

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

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

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

Item 1B. *Unresolved Staff Comments*

We do not have any unresolved staff comments.

Item 2. *Properties*

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

Title to Properties

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

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

Item 3. *Legal Proceedings*

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

In December 2008, Denbury Onshore, LLC ("Denbury") initiated formal arbitration proceedings against Crosstex CCNG Processing Ltd. ("Crosstex Processing"), Crosstex Energy Services, L.P. ("Crosstex Energy"), Crosstex North Texas Gathering, L.P. ("Crosstex Gathering") and Crosstex Gulf Coast Marketing, Ltd. ("Crosstex Marketing"), all wholly-owned subsidiaries of us, asserting a claim for breach of contract under a gas processing agreement. Denbury alleged damages in the amount of $16.2 million, plus interest and attorneys' fees. We denied any liability and sought to have the action dismissed. A three-person arbitration panel conducted a hearing on the merits in December 2009. At the close of the evidence at the hearing, the panel granted judgment for us on one of Denbury's claims, and on February 16, 2010, the panel granted judgment for Denbury on its remaining claims in the amount of $3.0 million plus interest, attorneys' fees and costs. The panel will conduct additional proceedings to determine the amount of attorneys' fees and costs, if any, that should be awarded to Denbury. We estimate that the total award will be between $3.0 million and $4.0 million at the conclusion of these additional proceedings and a liability for this award was accrued as of December 31, 2009.

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

We (or our subsidiaries) are defending several lawsuits filed by owners of property located near processing facilities or compression facilities constructed by us as part of our systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. Although it is not possible to predict the ultimate outcomes of these matters, we do not believe that these claims will have a material adverse impact on 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 $2.3 million for July 2008 sales. We believe the July sales of $2.3 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to us for an administrative claim in the amount of $2.3 million, but it remains subject to an objection by the lenders' agent. We evaluated these receivables for collectibility and recorded a provision for bad debts of $3.1 million during the year ended December 31, 2008 and $0.8 million during the year ended December 31, 2009.

Item 4. ***Reserved***

PART II

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

Our common units are listed on the NASDAQ Global Select Market under the symbol "XTEX". On February 16, 2010, the closing market price for the common units was $9.50 per unit and there were approximately 13,000 record holders and beneficial owners (held in street name) of our common units.

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

	Common Unit Price Range(a)		Cash Distribution
	High	Low	Paid Per Unit(a)
2009:			
Quarter Ended December 31	$ 8.60	$ 4.92	—
Quarter Ended September 30	5.34	2.45	—
Quarter Ended June 30	4.16	1.92	—
Quarter Ended March 31	7.17	1.17	—
2008:			
Quarter Ended December 31	$ 17.41	$ 3.50	$ 0.25
Quarter Ended September 30	28.33	18.16	0.50
Quarter Ended June 30	34.10	28.40	0.63
Quarter Ended March 31	32.67	30.03	0.62

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

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

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or

- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters;

- plus all cash on hand for the quarter resulting from working capital borrowings made after the end of the quarter on the date of determination of available cash.

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

Our ability to make distributions was contractually restricted by the terms of our credit facilities during 2009 due to our high leverage ratios. Although our new credit facility does not limit our ability to make distributions as long as we are not in default of such facility (and the indenture governing our senior unsecured notes requires us to meet a ratio test), any decision to resume cash distributions on our units and the amount of any such distributions would consider maintaining sufficient cash flow in excess of the distribution to continue to move towards lower leverage ratios. We have established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA of less than 4.0 to 1.0, and we do not currently expect to resume cash distributions on our outstanding units until we achieve such a ratio of less than 4.5 to 1.0 (pro forma for any distribution). We will also consider general economic conditions and our outlook for our business as we determine to pay any distribution.

On January 19, 2010, we issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions. The 14,705,882 preferred units are convertible at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. We have the right to force conversion of the preferred units after three years if (i) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 days ending on two trading days before the date on which we deliver notice of such conversion, and (ii) the average daily trading volume of common units must have exceeded 250,000 common units for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion. The preferred units are not redeemable but will pay a quarterly distribution that will be the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if we pay a cash distribution on common units.

Item 6. *Selected Financial Data*

The following table sets forth selected historical financial and operating data of Crosstex Energy, L.P. as of and for the dates and periods indicated. The revised selected historical financial data are derived from the audited financial statements of Crosstex Energy, L.P. and have been revised to reflect 2009 asset dispositions as discontinued operations and to move letter of credit fees to interest expense from purchased gas expense. In addition, our summary historical financial and operating data include the results of operations of the south Louisiana processing assets beginning November 2005, the NTP beginning April 2006 and the Chief midstream assets beginning June 2006 and other smaller acquisitions completed in 2006.

The table should be read together with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Crosstex Energy, L.P.				
	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Midstream	$ 1,453,346	$ 3,072,646	$ 2,380,224	$ 1,534,800	$ 1,212,864
Gas and NGL marketing activities	5,744	3,365	4,105	2,535	1,599
Total revenues	1,459,090	3,076,011	2,384,329	1,537,335	$ 1,214,463
Operating costs and expenses:					
Purchased gas	1,147,868	2,768,225	2,124,503	1,378,979	1,154,345
Operating expenses	110,394	125,754	91,202	65,871	28,958
General and administrative	59,854	68,864	59,493	43,710	30,693
(Gain) loss on derivatives	(2,994)	(8,619)	(4,147)	(174)	10,399
Gain on sale of property	(666)	(947)	(1,024)	(1,936)	(8,289)
Impairments	2,894	29,373	—	—	—
Depreciation and amortization	119,088	107,521	83,315	56,349	15,122
Total operating costs and expenses	1,436,438	3,090,171	2,353,342	1,542,799	1,231,228
Operating income (loss)	22,652	(14,160)	30,987	(5,464)	(16,765)
Other income (expense):					
Interest expense, net	(95,078)	(74,971)	(48,059)	(19,889)	(12,407)
Loss on extinguishment of debt	(4,669)	—	—	—	—
Other income	1,400	27,770	538	212	392
Total other income (expense)	(98,347)	(47,201)	(47,521)	(19,677)	(12,015)
Loss from continuing operations before non-controlling interest and income taxes	(75,695)	(61,361)	(16,534)	(25,141)	(28,780)
Income tax provision	(1,790)	(2,369)	(760)	(222)	(216)
Loss from continuing operations, net of tax	(77,485)	(63,730)	(17,294)	(25,363)	(28,996)
Income (loss) from discontinued operations, net of tax	(1,796)	25,007	31,343	20,714	48,637
Gain from sale of discontinued operations, net of tax	183,747	49,805	—	—	—
Discontinued operations	181,951	74,812	31,343	20,714	48,637
Net income (loss) before cumulative effect of change in accounting principle	104,466	11,082	14,049	(4,649)	19,641
Cumulative effect of change in accounting principle	—	—	—	689	—
Net income (loss)	104,466	11,082	14,049	(3,960)	19,641
Less: Net income from continuing operations attributable to the non-controlling interest	60	311	160	231	441
Net income (loss) attributable to Crosstex Energy, L.P.	$ 104,406	$ 10,771	$ 13,889	$ (4,191)	$ 19,200
Net income (loss) per limited partner unit — basic	$ 1.44	$ (3.19)	$ (0.20)	$ (1.09)	$ 0.56
Net income (loss) per limited partner unit — diluted	$ 1.40	$ (3.19)	$ (0.20)	$ (1.09)	$ 0.51
Net income per limited partner senior subordinated unit	$ 8.85	$ 9.44	$ —	$ 5.31	$ —
Distributions declared per limited partner unit (1)	$ —	$ 2.00	$ 2.33	$ 2.18	$ 1.93

	Crosstex Energy, L.P.				
	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per unit data)				
Balance Sheet Data (end of period):					
Working capital deficit	$ (50,320)	$ (32,910)	$ (46,888)	$ (79,936)	$ (11,681)
Property and equipment, net	1,279,060	1,527,280	1,425,162	1,105,813	667,142
Total assets	2,069,181	2,533,266	2,592,874	2,194,474	1,425,158
Long-term debt	873,702	1,263,706	1,223,118	987,130	522,650
Partners' equity including non-controlling interest	893,282	797,931	788,641	715,532	405,559
Cash Flow Data:					
Net cash flow provided by (used in)(2):					
Operating activities	$ 80,978	$ 173,750	$ 114,818	$ 113,010	$ 14,010
Investing activities	379,874	(186,810)	(411,382)	(885,825)	(615,017)
Financing activities	(461,709)	14,554	295,882	772,234	596,615
Other Financial Data:					
Gross margin(3)	$ 311,222	$ 307,786	$ 259,826	$ 158,356	$ 60,118
Operating Data:					
Pipeline throughput (MMBtu/d)	2,040,000	2,002,000	1,555,000	845,000	582,000
Natural gas processed (MMBtu/d)(4)	1,235,000	1,608,000	1,835,000	1,817,000	1,707,000
Producer services (MMBtu/d)	75,000	85,000	94,000	138,000	111,010

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

(2) Cash flow data includes cash flows from discontinued operations.

(3) Gross margin is defined as revenue, including Gas and NGL marketing activities, less related cost of purchased gas.

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

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

You should read the following discussion of our financial condition and results of operations in conjunction with the financial statements and notes thereto included elsewhere in this report. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the financial statements included in this report.

Overview

We are a Delaware limited partnership formed on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. Historically, we have operated 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. In February 2009, we sold our Oklahoma assets; in August 2009 we sold our Alabama, Mississippi and south Texas Midstream properties; and in October 2009 we sold our Treating assets, all as more fully described under "Recent Developments and Business Strategy." Our primary focus for our continuing operations is on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, which constitute one reporting segment of midstream activity. Currently, our geographic focus is in the north Texas Barnett shale area and in Louisiana. We manage our operations by focusing on gross margin because our business is generally to purchase and resell natural gas for a margin, or to gather, process, transport or market natural gas or NGLs for a fee. We buy and sell most of our natural gas at a fixed relationship to the relevant index price. In addition, we receive certain fees for processing based on a percentage of the liquids produced and enter into hedge contracts for our expected share of the liquids produced to protect our margins from changes in liquids prices.

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

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

We generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. We are also party to certain long-term gas sales commitments that we satisfy through supplies purchased under long-term gas purchase agreements. When we enter into those arrangements, our sales obligations generally match our purchase obligations. However, over time the supplies that we have under contract may decline due to reduced drilling or other causes and we may be required to satisfy the sales obligations by buying additional gas at prices that may exceed the prices received under the sales commitments. In our purchase/sale transactions, the resale price is generally based on the same index at which the gas was purchased. However, we have certain purchase/sale transactions in which the purchase price is based on a production-area index and the sales price is based on a market-area index, and we capture the difference in the indices (also referred to as basis spread), less the transportation expenses from the two areas, as our margin. Changes in the basis spread can increase or decrease our margins (or even be negative at times).

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

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

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

Recent Developments and Business Strategy

From our inception in 2002 until the second half of 2008, our long-term strategy had 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 the volatility in the commodity and capital markets over the last 18 months and other events, including the substantial decline in commodity prices, we adjusted our business strategy in the fourth quarter 2008 and in 2009 to focus on maximizing our liquidity, improving our balance sheet through debt reduction and other methods, maintaining a stable asset base, improving the profitability of our assets by increasing their utilization while controlling costs and reducing our capital expenditures. Consistent with this strategy, we divested non-core assets since October 2008 for aggregate sale proceeds of $618.7 million and substantially reduced our outstanding debt. We plan to continue our focus on (i) improving existing system profitability, (ii) continuing to improve our balance sheet and financial flexibility and (iii) pursuing strategic acquisitions and undertaking selective construction and expansion opportunities. We are successfully executing our plan as highlighted by the following accomplishments:

- *Sold Non-Core Assets.* We sold $618.7 million of non-core assets and repaid approximately $500 million in long-term indebtedness from the sales proceeds over the last 15 months. In November 2008 we sold our 12.4% interest in the Seminole gas processing plant for $85.0 million. In the first quarter of 2009, we sold our Arkoma system for approximately $10.7 million. In August 2009, we sold our midstream assets in Alabama, Mississippi and south Texas for approximately $217.6 million. In addition, in October 2009, we sold our natural gas treating business for $265.4 million. We also sold our east Texas midstream assets on January 15, 2010 for $40.0 million.

- *Reduced Capital Expenditures.* We reduced our capital expenditures from over $275.6 million for 2008 to $101.4 million in 2009 and focused our capital projects on lower risk projects with higher expected returns.

- *Reduced Operating and General and Administrative Expenses.* We reduced our operating expenses from continuing operations to $110.4 million for the year ended December 31, 2009 from $125.8 million for the year December 31, 2008 and our general and administrative expenses from continuing operations to $59.9 million for the year ended December 31, 2009 from $68.9 million for the year December 31, 2008 by reducing staffing and controlling costs. General and administrative expenses for the year ended December 31, 2009 also include non-recurring costs totaling $4.4 million associated with severance payments, lease termination costs and bad debt expense due to the SemStream, L.P. bankruptcy.

- *Acquired Certain Assets in Our Core Areas.* We acquired the Eunice NGL processing plant and fractionation facility in October 2009 for $23.5 million in cash and the assumption of $18.1 million in debt. We originally acquired the contract rights associated with the Eunice plant as part of the south Louisiana acquisition in November 2005 and operated and managed the plant under an operating lease with an unaffiliated third party prior to the recent acquisition. This acquisition will eliminate lease obligations of $12.2 million per year. We also acquired the Intracoastal Pipeline located in southern Louisiana for approximately $10.3 million in December 2009. Both of these acquisitions were designed to enhance our NGL business.

- *Sale of Preferred Units.* On January 19, 2010, we issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions. The 14,705,882 preferred units are convertible at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. We have the right to force conversion of the preferred units after three years if (i) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 days ending on two trading days before the date on which we deliver notice of such conversion, and (ii) the average daily trading volume of common units must have exceeded 250,000 common units for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion. The preferred units are not redeemable but will pay a quarterly distribution that will be the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if we pay a cash distribution on common units.

- *Issuance of Senior Unsecured Notes.* On February 10, 2010, we issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes due 2018 at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under our new credit facility discussed below, were used to repay in full amounts outstanding under our existing bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with our existing credit facility.

The notes are unsecured and unconditionally guaranteed on a senior basis by certain of our direct and indirect subsidiaries, including substantially all of our current subsidiaries. Interest payments will be paid semi-annually in arrears starting in August 2010. We have the option to redeem all or a portion of the notes at any time on or after February 15, 2014, at the specified redemption prices. Prior to February 15, 2014, we may redeem the notes, in whole or in part, at a “make-whole” redemption price. In addition, we may redeem up to 35% of the notes prior to February 15, 2013 with the cash proceeds from certain equity offerings.

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

Acquisitions and Expansion Prior to 2009

We grew significantly through asset purchases and construction and expansion projects in years prior to 2009. As discussed above, we disposed of certain assets during late 2008 and 2009 to refocus our business on the gathering, processing, transmission and marketing of natural gas and NGLs in the north Texas Barnett Shale area and in Louisiana. These acquisitions and dispositions create many of the major differences when comparing operating results from one period to another. The most significant asset purchase since January 2006 was the acquisition of midstream assets from Chief in June 2006. In addition, internal expansion projects in north Texas and Louisiana have contributed to the increase in our business during 2006, 2007, 2008 and 2009. We also acquired treating assets during 2006 that were included in the sale of our Treating business in 2009 as discussed above.

On June 29, 2006, we expanded our operations in the north Texas area through our acquisition of the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. The continued expansion of our north Texas gathering systems to handle the growing production in the Barnett Shale was one of our core areas for internal growth during 2006, 2007, 2008 and 2009. Since the date of the acquisition through December 31, 2009, we have expanded our gathering system, connected in excess of 500 new wells to our north Texas gathering system and significantly increased the productive acreage dedicated to our systems. As of December 31, 2009, total capacity on our north Texas gathering system was approximately 1,100 MMcf/d and total throughput was approximately 793,000 MMBtu/d for the year ended December 31, 2009. Since 2006, we have constructed three gas processing plants with a total processing capacity in the Barnett Shale of 280 MMcf/d, including our Silver Creek plant, which is a 200 MMcf/d cryogenic processing plant, our Azle plant, which is a 50 MMcf/d cryogenic processing plant and our Goforth plant, which is a 30 MMcf/d processing plant. Total processing throughput averaged 219,000 MMBtu/d for the year ended December 31, 2009.

In 2007, we extended our Crosstex LIG system to the north to reach additional productive areas in the developing natural gas fields south of Shreveport, Louisiana, primarily in the Cotton Valley formation. This extension, referred to as the north Louisiana expansion, consists of 63 miles of 24” mainline with 9 miles of gathering lateral pipeline. Our north Louisiana expansion bisects the developing Haynesville Shale gas play in north Louisiana. The north Louisiana expansion was operating at near capacity during 2008 as Haynesville gas was beginning to develop so we added 35 MMcf/d of capacity by adding compression during the third quarter of 2008 bringing the total capacity of the north Louisiana expansion to approximately 275 MMcf/d. We continued the expansion of our north Louisiana system during 2009 increasing capacity by 100 MMcf/d in July 2009 by adding compression. We increased our capacity by another 35 MMcf/d with a new interconnect into an interstate pipeline in December 2009 and bringing total capacity to 410 MMcf/d by the end of 2009. We have long-term firm transportation agreements subscribing to all of the incremental capacity added during 2009. In addition, we added compression during 2009 between the southern portion of our Crosstex LIG system and the northern expansion of our Crosstex LIG system, which increased the capacity to bring gas from the north to our markets in the south to 145 MMcf/d. Interconnects on the north Louisiana expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission, Trunkline Gas and Tennessee Gas Pipeline.

Commodity Price Risk

We are subject to significant risks due to fluctuations in commodity prices. Our exposure to these risks is primarily in the gas processing component of our business. A large percentage of our processing fees are realized under POL contracts that are directly impacted by the market price of NGLs. We also realize processing gross margins under margin contracts. These settlements are impacted by the relationship between NGL prices and the underlying natural gas prices, which is also referred to as the fractionation spread.

A significant volume of inlet gas at our south Louisiana and north Texas processing plants is settled under POL agreements. The POL fees are denominated in the form of a share of the liquids extracted and we are not responsible for the fuel or shrink associated with processing. Therefore, revenue under a POL agreement is directly impacted by NGL prices, and the decline of these prices in the second half of 2008 and early 2009 contributed to a significant decline in our gross margin from processing.

We have a number of margin contracts on our Plaquemine and Gibson processing plants that expose us to the fractionation spread. Under these margin contracts our gross margin is based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state ("shrink") and the cost of fuel to extract during processing. During the second half of 2008 and early 2009, 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. Such a decline may negatively impact our gross margin in the future if we have such declines again.

We are also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transportation services. Approximately 8.0% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices.

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

Results of Operations

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

	Years Ended December 31,		
	2009	2008	2007
	(Dollars in millions)		
Midstream revenues	$ 1,453.3	$ 3,072.6	$ 2,380.2
Purchased gas	(1,147.8)	(2,768.2)	(2,124.5)
Gas and NGL marketing activities	5.7	3.4	4.1
Total gross margin	$ 311.2	$ 307.8	$ 259.8
Volumes (MMBtu/d):			
Gathering and transportation	2,040,000	2,002,000	1,555,000
Processing	1,235,000	1,608,000	1,835,000
Producer services	75,000	85,000	94,000

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Gross Margin and Gas and NGL Marketing Activities. Midstream gross margin was $311.2 million for the year ended December 31, 2009 compared to $307.8 million for the year ended December 31, 2008, an increase of $3.4 million, or 1.1%. The increase was primarily due to higher margins on our gathering and transmission throughput volume. These increases were partially offset by gross margin declines in the processing business due to a less favorable NGL market. Gas and NGL marketing activities increased for the comparative periods by approximately $2.4 million primarily due to an improved fee structure and an increase in activity in the liquids marketing business.

The LIG gathering and transmission system contributed gross margin growth of $14.0 million for the year ended December 31, 2009 over the same period in 2008 primarily due to improved pricing and higher volumes on the northern part of the system offsetting a decrease in sales volume at southern delivery points. The north Texas region contributed $13.9 million of gross margin growth for the comparative periods primarily due to increased volume on the gathering systems. The gross margin increase contributed by the north Texas region was partially offset by an increase in purchased gas costs of $3.7 million related to the arbitration award to Denbury discussed under "Contingencies." The weaker processing environment contributed to a significant decline in the gross margins for processing plants in Louisiana for the year ended December 31, 2009. Overall the plants in the region reported a margin decrease of approximately $15.1 million. The primary contributors to this decrease were the Gibson, Plaquemine and Blue Water processing plants which had gross margin declines of $9.8 million, $7.6 million and $3.5 million, respectively. These declines were partially offset by an increase of approximately $8.3 million in the fractionation and liquids marketing activities in the region. The Arkoma system, which was sold in April 2009, created a negative gross margin variance of $4.0 million when compared to the same period in 2008. The Crosstex Pipeline system in east Texas had a gross margin decline of $1.7 million primarily due to a decline in throughput volumes.

Operating Expenses. Operating expenses were $110.4 million for the year ended December 31, 2009 compared to $125.8 million for the year ended December 31, 2008, a decrease of $15.4 million, or 12.2%, resulting primarily from initiatives undertaken in late 2008 and early 2009 to reduce expenses.

General and Administrative Expenses. General and administrative expenses were $59.9 million for the year ended December 31, 2009 compared to $68.9 million for the year ended December 31, 2008, a decrease of $9.0 million, or 13.1%. The decrease is a result of strategic initiatives undertaken to reduce expenses and primarily relate to workforce reductions. The 2009 amount includes $4.4 million of non-recurring costs consisting of $3.1 million of severance payments, $0.8 million of lease termination costs and $0.5 million of bad debt expense due to the SemStream, L.P. bankruptcy.

Gain/Loss on Derivatives. We had a gain on derivatives of $3.0 million for the year ended December 31, 2009 compared to a gain of $8.6 million for the year ended December 31, 2008. The derivative transaction types contributing to the net gain are as follows (in millions):

	Years Ended December 31,			
	2009		2008	
(Gain) Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ (4.4)	$ (2.5)	$ (8.7)	$ (8.8)
Processing margin hedges	1.4	(2.2)	(3.6)	(3.6)
Storage	(0.3)	(1.1)	(0.7)	(0.1)
Third-party on-system swaps	(0.1)	(0.3)	(0.6)	(0.8)
Other	0.1	—	(0.1)	—
	(3.3)	(6.1)	(13.7)	(13.3)
Derivative gains included in income from discontinued operations	0.3	0.5	5.1	5.4
	$ (3.0)	$ (5.6)	$ (8.6)	$ (7.9)

Impairments. During the year ended December 31, 2009, we had an impairment expense of $2.9 million compared to $29.4 million for the year ended December 31, 2008. During 2009, impairments totaling $2.9 million were taken on the Bear Creek processing plant and the Vermillion treating plant to bring the fair value of the plants to a marketable value for these idle assets. The impairment expense during 2008 is comprised of:

- $17.8 million related to the Blue Water gas processing plant located in south Louisiana — The impairment on our 59.27% interest in the Blue Water gas processing plant was recognized because the pipeline company which owns the offshore Blue Water system and supplies gas to our Blue Water plant reversed the flow of the gas on its pipeline in early January 2009 thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system. As of January 2009, we had not found an alternative source of new gas for the Blue Water plant so the plant ceased operation from January 2009 until November 2009. An impairment of $17.8 million was recognized for the carrying amount of the plant in excess of the estimated fair value of the plant as of December 31, 2008.

- $4.9 million related to goodwill — We determined that the carrying amount of goodwill attributable to the Midstream segment was impaired because of the significant decline in our Midstream operations due to negative impacts on cash flows caused by the significant declines in natural gas and NGL prices during the last half of 2008 coupled with the global economic decline.

- $4.1 million related to leasehold improvements — We had planned to relocate our corporate headquarters during 2008 to a larger office facility. We had leased office space and were close to completing the renovation of this office space when the global economic decline began impacting our operations in October 2008. On December 31, 2008, the decision was made to cancel the new office lease and not relocate the corporate offices from its existing office location. The impairment relates to the leasehold improvements on the office space for the cancelled lease.

- $2.6 million related to the Arkoma gathering system — The impairment on the Arkoma gathering system was recognized because we sold this asset in February 2009 for $10.7 million and the carrying amount of the plant exceeded the sale price by approximately $2.6 million.

Depreciation and Amortization. Depreciation and amortization expenses were $119.1 million for the year ended December 31, 2009 compared to $107.5 million for the year ended December 31, 2008, an increase of $11.6 million, or 10.8%, resulting primarily from growth and expansion in the NTP, NTG and north Louisiana areas.

Interest Expense. Interest expense was $95.1 million for the year ended December 31, 2009 compared to $75.0 million for the year ended December 31, 2008, an increase of $20.1 million, or 26.8%. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2009	2008
Senior notes	$ 28.3	$ 22.5
PIK	4.9	—
Credit facility	30.7	20.8
Series B secured note	0.4	—
Capitalized interest	(1.1)	(2.7)
Mark to market interest rate swaps	(0.8)	22.1
Realized interest rate swaps	19.0	4.6
Interest income	(0.2)	(0.3)
Amortization of debt issue cost	7.6	2.9
Other	6.3	5.1
Total	$ 95.1	$ 75.0

Loss on Extinguishment of Debt. We recognized a loss on extinguishment of debt during the year ended December 31, 2009 of $4.7 million due to the February 2009 amendment to the senior secured notes agreement. The modifications to this agreement pursuant to this amendment were substantive as defined in FASB ASC 470-50 and were accounted for as the extinguishment of the old debt and the creation of new debt. As a result, the unamortized costs associated with the senior secured notes prior to the amendment as well as the fees paid to the senior secured lenders for the February 2009 amendment were expensed during the year ended December 31, 2009.

Other Income. Other income was $1.4 million for the year ended December 31, 2009 compared to $27.8 million for the year ended December 31, 2008. In November 2008, we 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.

Income Taxes. Income tax expense was $1.8 million for the year ended December 31, 2009 compared to $2.4 million for the year ended December 31, 2008, a decrease of $0.6 million. The decrease in expense between periods was because the income tax expense for the year ended December 31, 2008 included an adjustment of $0.9 million for an unrecognized tax benefit related to the Texas margin tax.

Discontinued Operations. We sold the following non-strategic assets over the past year and used the proceeds from such sales to repay long-term indebtedness:

Assets	Date of Sale
12.4% interest in the Seminole Gas Processing Plant	November 2008
Oklahoma assets (Arkoma system)	February 2009
Alabama, Mississippi and south Texas assets	August 2009
Treating assets	October 2009

In accordance with FASB ASC 360-10-05-4, the results of operations related to each of the assets listed above (except the Arkoma assets which were immaterial to the financial statement presentations) are presented in income from discontinued operations for the comparative periods in the statements of operations. Revenues, operating expenses, general and administrative expenses associated directly to the assets sold, depreciation and amortization, allocated Texas margin tax and allocated interest are reflected in the income from discontinued operations. During the year ended December 31, 2009, we expensed $4.3 million in borrowings of unamortized debt issuance costs associated with the bank credit facility and the senior secured notes due to the repayments of $316.3 million and $153.8 million, respectively, from proceeds of the Alabama, Mississippi and south Texas assets and Treating assets dispositions. In addition, we incurred make-whole interest and call premiums of $5.2 million in the year ended December 31, 2009 to the holders of the senior secured notes due to the call premiums on the repayments. These additional interest costs are included in discontinued operations for the year ended December 31, 2009. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are the components of revenues and earnings from discontinued operations and operating data (dollars in millions):

	Year Ended December 31,	
	2009	2008
Midstream revenues	$ 368.1	$ 1,766.1
Treating revenues	$ 45.5	$ 73.5
Income (loss) from discontinued operations, net of tax	$ (1.8)	$ 25.0
Gain from sale of discontinued operations, net of tax	$ 183.7	$ 49.8
Gathering and Transmission Volumes (MMBtu/d)	564,000	617,000
Processing Volumes (MMBtu/d)	191,000	204,000

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

Gross Margin and Gas and NGL Marketing Activities. Midstream gross margin was $307.8 million for the year ended December 31, 2008 compared to $259.8 million for the year ended December 31, 2007, an increase of $48.0 million, or 18.5%. 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 due to the impact of hurricanes in the last half of the year. Gas and NGL marketing 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 gathering systems in the region and NTP accounted for $41.3 million and $9.1 million of this increase, respectively. The 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 due to the impact of hurricanes along the Gulf Coast.

Our processing and gathering systems were negatively impacted by events beyond our control during the third quarter that had a significant effect on gross margin results for the year ended December 31, 2008. Hurricanes Gustav and Ike came ashore along the Gulf Coast in September 2008. These storms are estimated to have cost approximately $22.9 million in gross margin 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 plant in August 2008 due to downtime from fire damage. The fire occurred during an attempt to bring the plant back online following tropical storm Edouard.

Operating Expenses. Operating expenses were $125.8 million for the year ended December 31, 2008 compared to $91.2 million for the year ended December 31, 2007, an increase of $34.6 million, or 37.9%, resulting primarily from growth and expansion in the NTP, NTG, north Louisiana and east Texas areas. The increase is primarily attributable to the following factors:

- Contractor services and labor costs increased $12.3 million;
- Chemical and materials increased $6.2 million;
- Equipment rental increased $5.8 million;
- Ad valorem taxes increased $2.2 million; and
- Technical services increased $0.7 million.

General and Administrative Expenses. General and administrative expenses were $68.9 million for the year ended December 31, 2008 compared to $59.5 million for the year ended December 31, 2007, an increase of $9.4 million, or 15.8%. The increase is primarily attributable to the following factors:

- $5.5 million increase in rental expense resulting primarily from additional office rent and including $3.4 million related to lease termination fees for the cancelled relocation of our corporate headquarters;
- $3.1 million increase in bad debt expense due to the SemStream, L.P. bankruptcy;
- $1.8 million increase in professional fees and services; 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 $8.6 million for the year ended December 31, 2008 compared to a gain of $4.1 million for the year ended December 31, 2007. The derivative transaction types contributing to the net gain are as follows (in millions):

	Years Ended December 31,			
	2008		2007	
(Gain)/Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ (8.7)	$ (8.8)	$ (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	—
	(13.7)	(13.3)	(6.6)	(7.9)
Derivative gains included in income from discontinued operations	5.1	5.4	2.5	2.8
	$ (8.6)	$ (7.9)	$ (4.1)	$ (5.1)

Impairments. During the year ended December 31, 2008, we had an impairment expense of $29.4 million compared to no impairment expense for the year ended December 31, 2007. The 2008 impairment expense is described under "Year Ended December 31, 2009 Compared to Year Ended December 31, 2008".

Depreciation and Amortization. Depreciation and amortization expenses were $107.5 million for the year ended December 31, 2008 compared to $83.3 million for the year ended December 31, 2007, an increase of $24.2 million, or 29.1%. Depreciation and amortization increased $22.5 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 $75.0 million for the year ended December 31, 2008 compared to $48.1 million for the year ended December 31, 2007, an increase of $26.9 million, or 56.0%. The increase relates primarily to the negative impact of declining interest rates on our interest rate swaps. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2008	2007
Senior notes	$ 22.5	$ 23.0
Credit facility	20.8	24.8
Capitalized interest	(2.7)	(4.8)
Mark to market interest rate swaps	22.1	1.2
Realized interest rate swaps	4.6	(0.7)
Interest income	(0.3)	(0.7)
Amortization of debt issue cost	2.9	2.6
Other	5.1	2.7
Total	$ 75.0	$ 48.1

Other Income. Other income was $27.8 million for the year ended December 31, 2008 compared to $0.5 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 and $7.0 million from the settlement of disputed liabilities that were assumed with an acquisition.

Income Taxes. Income tax expense was $2.4 million for the year ended December 31, 2008 compared to $0.8 million for the year ended December 31, 2007, an increase of $1.6 million. The increase relates primarily to the Texas margin tax.

Discontinued Operations. Income from discontinued operations was $74.8 million for the year ended December 31, 2008 compared to $31.3 million for the year ended December 31, 2007. Discontinued operations includes income related to the Seminole gas processing plant disposed of in November 2008, income related to the Alabama, Mississippi and south Texas assets disposed of in August 2009 and income related to the Treating assets disposed of in October 2009. The reported income for the comparative periods has been recast to include 2009 dispositions in income from discontinued operations.

Critical Accounting Policies

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

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

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

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

We use derivatives to hedge against changes in cash flows related to product prices and interest rate risks, as opposed to their use for trading purposes. FASB ASC 815 requires that all derivatives and hedging instruments are recognized as assets or liabilities at fair value. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

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

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

Impairment of Long-Lived Assets. In accordance with FASB ASC 360-10-05, we evaluate the long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on management's estimate of undiscounted future cash flows attributable to the assets as compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value for the assets and recording a provision for loss if the carrying value is greater than fair value.

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

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

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

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

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

Liquidity and Capital Resources

Cash flow presented in liquidity discussions includes cash flow from discontinued operations.

Cash Flows from Operating Activities. Net cash provided by operating activities was $81.0 million, $173.8 million and $114.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. Income before non-cash income and expenses and changes in working capital for 2009, 2008 and 2007 were as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Income before non-cash income and expenses	$ 89.8	$ 160.9	$ 138.9
Changes in working capital	(8.8)	12.9	(24.0)

The primary reason for the decreased cash flow from income before non-cash income and expenses of $71.1 million from 2008 to 2009 was increased interest expense of $19.4 million, decreased operating income of $11.2 million, decreased other income of $26.8 million, and decreased gain on derivatives of $7.2 million. The primary reason for the increased cash flow from income before non-cash income and expenses of $22.0 million from 2007 to 2008 was increased operating income from our expansions in north Texas and north Louisiana during 2007 and 2008.

Cash Flows from Investing Activities. Net cash was provided from investing activities of $379.9 million for the year ended December 31, 2009 primarily due to proceeds from asset sales. Net cash used in investing activities was $186.8 million and $411.4 million for the years ended December 31, 2008 and 2007, respectively. Cash flows from investing activities for the years ended December 31, 2009, 2008 and 2007 include proceeds from property sales of $503.9 million, $88.8 million and $3.1 million, respectively. Sales in 2009 primarily relate to the sale of our Alabama, Mississippi, south Texas and Treating assets. Sales in 2008 primarily relate to the sale of our interest in the Seminole gas processing plant. The 2007 sales primarily relate to sales of inactive properties. Our primary investing activities for 2009, 2008 and 2007 were capital expenditures and acquisitions, net of accrued amounts, as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Growth capital expenditures	$ 90.5	$ 257.3	$ 403.7
Acquisitions and asset purchases	35.1	—	—
Maintenance capital expenditures	10.9	18.3	10.8
Total	$ 136.5	$ 275.6	$ 414.5

Net cash invested in Midstream assets was $123.8 million, $222.4 million and $385.8 million for the years ended December 31, 2009, 2008 and 2007, respectively. Net cash invested in Treating assets was $11.1 million, $41.8 million, and $23.5 million for the years ended December 31, 2009, 2008 and 2007, respectively. Net cash invested in other corporate assets was $1.6 million, $11.4 million and $5.2 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Cash Flows from Financing Activities. We disposed of non-core assets and repaid outstanding debt which resulted in net cash used by financing activities of $461.7 million for the year ended December 31, 2009. Net cash provided by financing activities was $14.6 million and $295.9 million for the years ended December 31, 2008 and 2007, respectively. Our financing activities primarily relate to funding of capital expenditures and acquisitions. Our financings have primarily consisted of borrowings and repayments under our bank credit facility, payments on senior secured notes, borrowings under capital lease obligations, equity offerings and senior note issuances in 2009, 2008 and 2007 as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Net borrowings under bank credit facility (1)	$ (254.4)	$ 50.0	$ 246.0
Senior secured note issuances (net of repayments) (2)	(163.2)	(9.4)	(9.4)
Net borrowings (payments) under capital lease obligations	(0.7)	23.9	3.6
Debt refinancing costs	(15.0)	(4.9)	(0.9)
Common unit offerings (3)	—	101.9	58.8
Senior subordinated unit offerings (3)	—	—	102.6

(1) Includes a $143.0 million and $173.3 million payment due to the sale of the Alabama, Mississippi and south Texas assets and the Treating assets.

(2) Includes a $69.0 million and $84.8 million payment due to sale of the Alabama, Mississippi and south Texas assets and the Treating assets.

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

Historically distributions to unitholders and our general partner represented our primary use of cash in financing activities. We ceased making distributions in the first quarter of 2009 due to liquidity issues and because the terms of our previous credit facility and senior secured note agreement restricted our ability to make distributions unless certain conditions were met. We did not meet these conditions during 2009. Total cash distributions made during the last three years were as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Common units	$ 11.4	$ 94.4	$ 49.8
Subordinated units	—	2.8	11.9
General partner	0.2	41.2	24.8
Total	$ 11.6	$ 138.4	$ 86.5

Our ability to make distributions was contractually restricted by the terms of our credit facilities during 2009 due to our high leverage ratios. Although our new credit facility does not limit our ability to make distributions as long as we are not in default of such facility (and the indenture governing our senior unsecured notes requires us to meet a ratio test), any decision to resume cash distributions on our units and the amount of any such distributions would consider maintaining sufficient cash flow in excess of the distribution to continue to move towards lower leverage ratios. We have established a target over the next couple of years of achieving a ratio of total debt to Adjusted EBITDA of less than 4.0 to 1.0, and we do not currently expect to resume cash distributions on our outstanding units until we achieve such a ratio of less than 4.5 to 1.0 (pro forma for any distribution). We will also consider general economic conditions and our outlook for our business as we determine to pay any distribution.

In order to reduce our interest costs, we do not borrow money to fund outstanding checks until they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on our revolving credit facility. Changes in drafts payable for 2009, 2008 and 2007 were as follows (in millions):

	Years Ended December 31,		
	2009	2008	2007
Increase (decrease) in drafts payable	$ (16.3)	$ (7.4)	$ (19.0)

Working Capital Deficit. We had a working capital deficit of $50.3 million as of December 31, 2009, primarily due to a net liability for our fair value of derivatives of $21.3 million and our current portion of long-term debt of $28.6 million related to our senior secured notes. Our fair value of derivatives reflects the mark-to-market of such derivatives including a net current liability of $18.0 million related to interest rate swaps and a net current liability of $3.3 million related to commodity derivatives. In February 2010, we repaid in full our senior secured notes and settled our interest rate swaps. Our changes in working capital may fluctuate significantly between periods even though our trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of our revenues are collected and a large volume of our gas purchases are paid near each month end or the first few days of the following month so receivable and payable balances at any month end my fluctuate significantly depending on the timing of these receipts and payments. In addition, although we strive to minimize our natural gas and NGLs in inventory, these working inventory balances may fluctuate significantly from period to period due to operational reasons and due to changes in natural gas and NGL prices. Our working capital also includes our mark to market derivative assets and liabilities associated with our commodity derivatives which may fluctuate significantly due to the changes in natural gas and NGL prices and associated with our interest rate swap derivatives which may fluctuate significantly due to changes in interest rates. The changes in working capital during the years ended December 31, 2009, 2008 and 2007 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, 2009 and 2008.

January 2010 Sale of Preferred Units. On January 19, 2010, we issued approximately $125.0 million of Series A Convertible Preferred Units to an affiliate of Blackstone/GSO Capital Solutions. The 14,705,882 preferred units are convertible at any time into common units on a one-for-one basis, subject to certain adjustments in the event of certain dilutive issuances of common units. We have the right to force conversion of the preferred units after three years if (i) the daily volume-weighted average trading price of the common units is greater than 150% of the then-applicable conversion price for 20 out of the trailing 30 days ending on two trading days before the date on which we deliver notice of such conversion, and (ii) the average daily trading volume of common units must have exceeded 250,000 common units for 20 out of the trailing 30 trading days ending on two trading days before the date on which we deliver notice of such conversion. The preferred units are not redeemable but will pay a quarterly distribution that will be the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if we pay a cash distribution on common units. The preferred units were issued at a discount to the market price of the common units they are convertible into. This discount totaling $22.3 million represents a beneficial conversion feature that will be reflected as a reduction in common unit equity upon issuance of the preferred units (which occurred on January 19, 2010) and will reduce earnings per common unit.

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

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

March 2007 Sale of Senior Subordinated Series D Units. On March 23, 2007, we issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests in a private offering for net proceeds of approximately $99.9 million. The senior subordinated series D units were issued at $25.80 per unit, which represented a discount of approximately 25% to the market value of common units on such date. The discount represented an underwriting discount plus the fact that the units would not receive a distribution nor be readily transferable for two years. Crosstex Energy GP, L.P. made a general partner contribution of $2.7 million in connection with this issuance to maintain its 2% general partner interest. The senior subordinated series D units automatically converted into common units on March 23, 2009 at a ratio of 1.05 common units for a total issuance of 4,069,106 common units. The senior subordinated series D units were not entitled to distributions of available cash or allocations of net income/loss from us until March 23, 2009.

Capital Requirements of the Partnership. We reduced our capital expenditures significantly for 2009 to improve our liquidity. Total capital expenditures during 2009 were less than $101.4 million. We utilized cash flow from operations and existing capacity under our bank credit facility to fund such expenditures. Our 2010 capital budget includes approximately $25.0 million of identified growth projects, and we expect to fund such expenditures with internally generated cash flow, with any excess cash flow applied towards debt, working capital or new projects. Although we expect to identify more growth projects during 2010 in addition to projects currently budgeted, we do not anticipate that our capital expenditures during 2010 will exceed $100.0 million.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2009 is as follows (in millions):

	Payments Due by Period						
	Total	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**
Long-Term Debt	$ 873.7	$ 28.6	$ 578.2	$ 93.0	$ 83.6	$ 67.4	$ 22.9
Interest Payable on Fixed Long-Term Debt Obligations	101.8	30.9	27.2	22.0	13.9	6.4	1.4
PIK Interest payable	19.0	—	19.0	—	—	—	—
Capital Lease Obligations	27.9	3.1	3.0	3.0	3.0	3.0	12.8
Operating Leases	56.6	15.9	12.1	9.3	6.2	4.7	8.4
Uncertain Tax Position Obligations	3.1	3.1	—	—	—	—	—
Total Contractual Obligations	$ 1,082.1	$ 81.6	$ 639.5	$ 127.3	$ 106.7	$ 81.5	$ 45.5

The above table does not include any physical or financial contract purchase commitments for natural gas due to the nature of both the price and volume components of such purchases, which vary on a daily or monthly basis. Additionally, we do not have contractual commitments for fixed price and/or fixed quantities of any material amount.

The contractual obligations reflected above have been presented without adjustment for changes in obligations due to the February 2010 repayment in full of obligations associated with our existing credit facility and senior secured notes with proceeds from the new credit facility and the new senior unsecured notes.

Description of Indebtedness

As of December 31, 2009 and 2008, long-term debt consisted of the following (in millions):

	2009	2008
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2009 and 2008 were 6.75% and 3.9%, respectively	$ 529.6	$ 784.0
Senior secured notes (including PIK notes as defined below of $9.5 million), weighted average interest rates at December 31, 2009 and 2008 of 10.5% and 8.0%, respectively	326.0	479.7
Series B secured note assumed in the Eunice transaction, which bears interest at the rate of 9.5%	18.1	—
	873.7	1,263.7
Less current portion	(28.6)	(9.4)
Debt classified as long-term	$ 845.1	$ 1,254.3

The balance of the bank credit facility and senior secured notes was paid in full on February 10, 2010 with the proceeds from the new credit facility and the senior unsecured notes.

Credit Facility. As of December 31, 2009, we had a bank credit facility with a borrowing capacity of $859.9 million that matures in June 2011. As of December 31, 2009, $683.0 million was outstanding under the bank credit facility, including $153.4 million of letters of credit, leaving approximately $176.9 million available for future borrowing.

New Credit Facility. In February 2010, we amended and restated our existing secured bank credit facility with a new syndicated secured bank credit facility. The new credit facility has a borrowing capacity of $420.0 million and matures in February 2014. Net proceeds from this credit facility along with net proceeds from the senior unsecured notes were used to, among other things, repay the previous bank credit facility and the senior secured notes.

The new credit facility will be guaranteed by substantially all of our subsidiaries. Obligations under the new credit facility will be secured by first priority liens on substantially all of our assets and those of the guarantors, including all material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in substantially all of our subsidiaries.

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

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

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

Based on our forecasted leverage ratio for 2010, we expect the applicable margin for the interest rate and letter of credit fee to be at the higher end of these ranges. The new credit facility will not have a floor for the Base Rate or the Eurodollar Rate.

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

The maximum permitted leverage ratio will be as follows:

- 5.75 to 1.00 for the fiscal quarters ending March 31, 2010 and June 30, 2010;
- 5.50 to 1.00 for the fiscal quarter ending September 30, 2010;
- 5.25 to 1.00 for the fiscal quarter ending December 31, 2010;
- 5.00 to 1.00 for the fiscal quarter ending March 31, 2011;
- 4.75 to 1.00 for the fiscal quarter ending June 30, 2011; and
- 4.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

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

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

- 1.50 to 1.00 for the fiscal quarter ending March 31, 2010;
- 1.75 to 1.00 for the fiscal quarters ending June 30, 2010 through December 31, 2010;
- 2.00 to 1.00 for the fiscal quarter ending March 31, 2011;

- 2.25 to 1.00 for the fiscal quarter ending June 30, 2011; and
- 2.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

In addition, the new credit facility will contain various covenants that, among other restrictions, will limit our ability to:

- grant or assume liens;
- make investments;
- incur or assume indebtedness;
- engage in mergers or acquisitions;
- sell, transfer, assign or convey assets,
- repurchase our equity, make distributions and certain other restricted payments;
- change the nature of our business;
- engage in transactions with affiliates.
- enter into certain burdensome agreements;
- make certain amendments to the omnibus agreement or our or our subsidiaries' organizational documents;
- prepay the senior unsecured notes and certain other indebtedness; and
- enter into certain hedging contracts.

The new credit facility will permit us to make quarterly distributions to unitholders so long as no default exists under the new credit facility.

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

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

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

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

We will be subject to interest rate risk on our new credit facility and may enter into interest rate swaps to reduce this risk.

We expect to be in compliance with the covenants in the new credit facility for the next twelve months.

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
June 2003	$ 1,607	9.45%
July 2003	1,000	9.38%
June 2004	50,629	9.46%
November 2005	57,380	8.73%
March 2006	40,504	8.82%
July 2006	165,390	9.46%
Total Outstanding	316,510	
PIK Notes Payable (1)	9,524	
Balance as of December 31, 2009 (2)	$ 326,034	

(1) The senior secured notes began accruing additional interest of 1.25% per annum in February 2009 (the "PIK notes") in the form of an increase in the principal amounts unless our leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter.

(2) The senior secured notes were paid in full on February 10, 2010.

Series B Secured Note. On October 20, 2009, the Partnership acquired the Eunice natural gas liquids processing plant and fractionation facility which includes $18.1 million in series B secured note. This note bears an interest rate of 9.5%. Payments including interest of $12.2 million and $7.4 million are due in 2010 and 2011, respectively.

Senior Unsecured Notes. On February 10, 2010, we issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under our new credit facility discussed above, were used to repay in full amounts outstanding under our existing bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with our existing credit facility. The notes are unsecured and unconditionally guaranteed on a senior basis by certain of our direct and indirect subsidiaries, including all of our current subsidiaries other than Crosstex LIG, LLC and Crosstex Tuscaloosa, LLC, our Louisiana regulated entities, and Crosstex DC Gathering, J.V. Interest payments will be paid semi-annually in arrears starting on August 15, 2010.

The indenture governing the notes contains covenants that, among other things, will limit our ability and the ability of certain of our subsidiaries to:

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

If the notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, many of these covenants will terminate.

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

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

Prior to February 15, 2014, we may redeem the notes, in whole or in part, at a "make-whole" redemption price. On or after February 15, 2014, we may redeem all or a part of the notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on February 15, 2014, 102.219% for the twelve-month period beginning February 15, 2015 and 100.00% for the twelve-month period beginning on February 15, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the notes.

Each of the following will be an event of default under the indenture:

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

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

Credit Risk

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

Inflation

Inflation in the United States has been relatively low in recent years in the economy as a whole. The midstream natural gas industry experienced an increase in labor and material costs during 2008, but 2009 remained relatively unchanged. These increases did not have a material impact on our results of operations for the periods presented. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental

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

Contingencies

In December 2008, Denbury initiated formal arbitration proceedings against Crosstex CCNG Processing Ltd. ("Crosstex Processing"), Crosstex Energy, Crosstex Gathering and Crosstex Marketing, all wholly-owned subsidiaries of the Partnership, asserting a claim for breach of contract under a gas processing agreement. Denbury alleged damages in the amount of $16.2 million, plus interest and attorneys' fees. Crosstex denied any liability and sought to have the action dismissed. A three-person arbitration panel conducted a hearing on the merits in December 2009. At the close of the evidence at the hearing, the panel granted judgment for Crosstex on one of Denbury's claims, and on February 16, 2010, the panel granted judgment for Denbury on its remaining claims in the amount of $3.0 million plus interest, attorneys' fees and costs. The panel will conduct additional proceedings to determine the amount of attorneys' fees and costs, if any, that should be awarded Denbury. We estimate that the total award will be between $3.0 million and $4.0 million at the conclusion of these additional proceedings. We have accrued $3.7 million in other current liabilities for this award as of December 31, 2009 and reflected the related expense in purchased gas costs.

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

The Partnership (or its subsidiaries) is defending several lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. 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 $2.3 million for July 2008 sales. The Partnership believes the July sales of $2.3 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 $2.3 million, but it remains subject to an objection by the lenders' agent. The Partnership evaluated these receivables for collectibility and provided a valuation allowance of $3.1 million and $0.8 million during the years ended December 31, 2008 and 2009, respectively.

Recent Accounting Pronouncements

As a result of the recent credit crisis, FASB ASC 820-10-35-15A was issued October 2008 and clarifies the application of FASB ASC 820 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. FASB ASC 820-10-35-15A is effective upon issuance, for companies that have adopted FASB ASC 820. We have evaluated FASB ASC 820-10-35-15A and determined that this standard has no impact on our results of operations, cash flows or financial position for this reporting period.

FASB ASC 260-10-45-60 was issued June 2008 and requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB ASC 260. FASB ASC 260-10-45-60 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. We adopted FASB ASC 260-10-45-60 effective January 1, 2009 and adjusted all prior periods to conform to the requirements.

FASB ASC 805 and FASB ASC 810-10-65-1 were issued December 2007. FASB ASC 805 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 FASB ASC 805 all business combinations will be accounted for by applying the acquisition method. FASB ASC 805 is effective for periods beginning on or after December 15, 2008. FASB ASC 810-10-65-1 requires 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. FASB ASC 810-10-65-1 was adopted effective January 1, 2009 and comparative period information has been recast to classify non-controlling interests in equity, and attribute net income and other comprehensive income to non-controlling interests.

FASB ASC 105 was released July 1, 2009 and intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of non-governmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. SFAS No. 162 has been superseded by SFAS No. 168, "*The FASB Accounting*

Standards Codification and the Hierarchy of Generally Accepted Accounting Principles" (the Codification) released July 1, 2009. The Codification became the exclusive authoritative reference for non-governmental U.S. GAAP for use in financial statements issued for interim and annual periods ending after September 15, 2009, except for Securities and Exchange Commission (SEC) rules and interpretive releases, which are also authoritative GAAP for SEC registrants. The change establishes non-governmental U.S. GAAP into the authoritative Codification and guidance that is non-authoritative. The contents of the Codification carry the same level of authority, eliminating the four-level GAAP hierarchy previously set forth in Statement 162. The Codification supersedes all existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the Codification has become non-authoritative. We have revised all GAAP references to reflect the Codification for the year ended December 31, 2009.

FASB ASC 815-10-65-1 was issued March 2008 and 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 FASB ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. FASB ASC 815-10-65-1 is effective for fiscal years beginning after November 15, 2008. FASB ASC 815-10-65-1 was adopted effective January 1, 2009. Required disclosures were added to Note 13.

FASB ASC 260-10-55-102 was released in March 2008 and addresses the consensus reached by the Task Force that incentive distribution rights (IDRs) in a typical master limited partnership are participating securities under FASB ASC 260, but earnings in excess of the partnership's "available cash" should not be allocated to the IDR holders for purposes of calculating earnings-per-share using the two-class method when "available cash" represents a specified threshold that limits participation. The consensus only applies when payments to IDR holders are accounted for as equity distributions. The consensus is effective for fiscal years beginning after December 15, 2008 and applied retrospectively to all periods presented. Under our partnership agreement, "available cash" is a specified threshold that limits participation for IDR holders. Therefore earnings in excess of our available cash, if any, are not allocated to IDR holders.

In June 2009 FASB ASC 810-10-05-8 was issued. It requires reporting entities to evaluate former Qualifying Special Purpose Entities or QSPEs for consolidation, changes the approach to determining a variable interest entity's (VIE) primary beneficiary from a quantitative assessment to a qualitative assessment designed to identify a controlling financial interest, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. This statement requires additional year-end and interim disclosures for public and nonpublic companies that are similar to the disclosures required by FASB ASC 860-10-65-2. The statement is effective for fiscal years beginning after November 15, 2009 and for subsequent interim and annual reporting periods. We do not expect this statement to have a significant impact to its financial statements.

FASB ASC 855 was issued June 2009 and is effective for interim or annual financial periods ending after June 15, 2009 and addresses accounting and disclosure requirements related to subsequent events. The statement requires management to evaluate subsequent events through the date the financial statements are issued. Companies are required to disclose the date through which subsequent events have been evaluated. We have taken this statement into consideration in Note 18.

FASB ASC 825-10-65-1 requires publicly traded companies to disclose the fair value of financial instruments within the scope of FASB ASC 825 in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. FASB ASC 825-10-65-1 is effective for interim and annual periods ending after June 15, 2009. We have added the required footnote disclosure in interim financial statements.

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 also exposed to the risk of changes in interest rates on floating rate debt.

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At December 31, 2009 and 2008, our bank credit facility had outstanding borrowings of $529.6 million and $784.0 million, respectively, which approximated fair value. We have managed a portion of our interest rate exposure on variable rate debt by utilizing interest rate swaps, which allow us to convert a portion of our variable rate interest into fixed rate interest. As of December 31, 2009, the fair value of these interest rate swaps was reflected as a liability of $24.7 million ($17.9 million in net current liabilities and $6.8 million in long-term liabilities) on our financial statements. We estimate that a 1% increase or decrease in the interest rate would increase or decrease the fair value of these interest rate swaps by approximately $12.7 million. Considering the amount outstanding on our bank credit facility as of December 31, 2009, we estimate that a 1% increase or decrease in the interest rate would change our annual interest expense by approximately $5.3 million.

At December 31, 2009 and 2008, we had total fixed rate debt obligations of $344.1 million and $479.7 million, respectively, consisting of senior secured notes with a weighted average interest rate of 10.5% and a series B secured note with a fixed rate of 9.5%. The fair value of these fixed rate obligations was approximately $342.7 million and $374.4 million as of December 31, 2009 and 2008, respectively. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of the fixed rated debt (the senior secured notes) by $9.6 million based on the debt obligations as of December 31, 2009.

The debt obligations discussed above and the related interest rate swaps were liquidated during February 2010 in the completion of our long-term recapitalization plan as discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — "Recent Developments and Business Strategy" under "Description of Indebtedness — Senior Unsecured Notes" and "Description of Indebtedness - New Credit Facility."

Commodity Price Risk

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

1. *Processing margin contracts*: Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") and the cost of fuel used in processing. The shrink and fuel losses are referred to as plant thermal reduction or PTR. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. However, we mitigate our risk of processing natural gas when our margins are negative under our current processing margin contracts primarily through our ability to bypass processing when it is not profitable for us, or by contracts that revert to a minimum fee for processing if the natural gas must be processed to meet pipeline quality specifications.

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

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

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

	Years Ended December 31,		
	2009	2008	2007
Gathering and transportation margin	65.8%	57.6%	45.1%
Gas processing margins:			
Processing margin	8.9%	15.4%	16.8%
Percent of liquids	13.2%	17.9%	28.1%
Fee based	12.1%	9.1%	10.0%
Total gas processing	34.2%	42.4%	54.9%
Total	100.0%	100.0%	100.0%

We have hedges in place at December 31, 2009 covering a portion of the liquids volumes we expect to receive under percent of liquids (POL) contracts as set forth in the following table. The relevant payment index price is the monthly average of the daily closing price for deliveries of commodities into Mont Belvieu, Texas as reported by the Oil Price Information Service (OPIS).

Period	Underlying	Notional Volume	We Pay	We Receive*	Fair Value Asset/(Liability) (In thousands)
January 2010-December 2010	Ethane	63 (MBbls)	Index	$0.5981/gal	$ (280)
January 2010-December 2010	Propane	109 (MBbls)	Index	$0.9584/gal	(1,236)
January 2010-December 2010	Normal Butane	40 (MBbls)	Index	$1.2580/gal	(420)
January 2010-December 2010	Natural Gasoline	21(MBbls)	Index	$1.4815/gal	(231)
					$ (2,167)

* weighted average

We have hedged our exposure to declines in prices for a portion of the NGL volumes produced for our account. The NGL volumes hedged, as set forth above, focus on our POL contracts. The portion of the POL exposure that we hedge is based on volumes we consider hedgeable (volumes committed under contracts that are long term in nature) versus total POL volumes that include volumes that may fluctuate due to contractual terms, such as contracts with month to month processing options. We have hedged 63.7% of our hedgeable volumes at risk through the end of 2010 (24.5% of our total volumes at risk).

We also have hedges in place at December 31, 2009 covering the fractionation spread risk related to our processing margin contracts as set forth in the following table:

Period	Underlying	Notional Volume	We Pay	We Receive	Fair Value Asset/(Liability) (In thousands)
January 2010-December 2010	Ethane	193 (MBbls)	Index	$0.5009/gal*	$ (1,467)
January 2010-December 2010	Propane	85 (MBbls)	Index	$0.9226/gal*	(1,063)
January 2010-December 2010	Normal Butane	57 (MBbls)	Index	$1.2007/gal*	(712)
January 2010-December 2010	Natural Gasoline	56 (MBbls)	Index	$1.5305/gal*	(476)
January 2010-December 2010	Natural Gas	4,695 (MMbtu/d)	$5.7096/MMBtu*	Index	92
					$ (3,626)

* weighted average

In relation to our fractionation spread risk, as set forth above, we have hedged 59.2% of our hedgeable liquids volumes at risk through the end of 2010 (32.7% of total liquids volumes at risk) and 62.6% of the related hedgeable PTR volumes through the end of 2010 (32.7% of total PTR volumes).

We are also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transport services. Approximately 8.0% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices.

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

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

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

As of December 31, 2009, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value liability of $2.9 million. The aggregate effect of a hypothetical 10% increase in gas and NGLs prices would result in an increase of approximately $2.3 million in the net fair value liability of these contracts as of December 31, 2009.

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-42 of this Report and are incorporated herein by reference.

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

None.

Item 9A. *Controls and Procedures*

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of Crosstex Energy, GP, LLC, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2009 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 control over financial reporting that occurred in the three months ended December 31, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control 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***

None.

PART III

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

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

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

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

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis	48	President, Chief Executive Officer and Director
William W. Davis	56	Executive Vice President and Chief Financial Officer
Joe A. Davis	49	Executive Vice President, General Counsel and Secretary
Michael J. Garberding	41	Senior Vice President—Finance
Stan Golemon	46	Senior Vice President of Engineering and Operations
Rhys J. Best**	63	Chairman of the Board and Member of the Conflicts Committee and Compensation Committee
Leldon E. Echols**	54	Director and Member of the Audit Committee*
Bryan H. Lawrence	67	Director
Sheldon B. Lubar**	80	Director and Member of the Governance Committee*
Cecil E. Martin**	68	Director and Member of the Audit Committee and Compensation Committee*
D. Dwight Scott	46	Director
Kyle D. Vann**	62	Director and Member of the Conflicts Committee* and Audit Committee

* Denotes chairman of committee.

** Denotes independent director.

Barry E. Davis, President, Chief Executive Officer and Director, led the management buyout of the midstream assets of Comstock Natural Gas, Inc. in December 1996, which transaction resulted in the formation of our predecessor. Mr. Davis has served as director since our IPO in December 2002. Mr. Davis was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis holds a B.B.A. in Finance from Texas Christian University. Mr. Davis also serves as Chairman of the Board for Crosstex Energy, Inc. Mr. Davis is not related to William W. Davis or Joe A. Davis. Mr. Davis' leadership skills and experience in the midstream natural gas industry, among other factors, led the Board to conclude that he should serve as a director.

William W. Davis, Executive Vice President and Chief Financial Officer, joined our predecessor in September 2001, and has over 30 years of finance and accounting experience. For more than the last seven years Mr. Davis has served as our Chief Financial Officer. Prior to joining our predecessor, Mr. Davis held various positions with Sunshine Mining and Refining Company from 1983 to September 2001, including Vice President—Financial Analysis from 1983 to 1986, Senior Vice President and Chief Accounting Officer from 1986 to 1991 and Executive Vice President and Chief Financial Officer from 1991 to 2001. In addition, Mr. Davis served as Chief Operating Officer in 2000 and 2001. Mr. Davis graduated magna cum laude from Texas A&M University with a B.B.A. in Accounting and is a Certified Public Accountant. Mr. Davis is not related to Barry E. Davis or Joe A. Davis.

Joe A. Davis, Executive Vice President, General Counsel and Secretary, joined Crosstex in October 2005. He began his legal career in 1985 with the Dallas firm of Worsham Forsythe, which merged with the international law firm of Hunton & Williams in 2002. Most recently, he served as a partner in the firm's Energy Practice Group, and served on the firm's Executive Committee. Mr. Davis specialized in facility development, sales, acquisitions and financing for the energy industry, representing entrepreneurial start up/development companies, growth companies, large public corporations and large electric and gas utilities. He received his J.D. from Baylor Law School in Waco and his B.S. degree from the University of Texas in Dallas. Mr. Davis is not related to Barry E. Davis or William W. Davis.

Michael J. Garberding, Senior Vice President — Finance joined Crosstex Energy GP, LLC in February 2008. Mr. Garberding has 20 years experience in finance and accounting. Prior to joining Crosstex, Mr. Garberding was assistant treasurer at TXU Corporation. In addition, Mr. Garberding worked at Enron North America as a Finance Manager and Arthur Andersen LLP as an Audit Manager. He received his Masters in Business Administration from the University of Michigan in 1999 and his B.B.A. in Accounting from Texas A&M University in 1991.

Stan Golemon, Senior Vice President of Engineering and Operations, joined Crosstex Energy GP, LLC in May of 2008. Mr. Golemon has 25 years of experience in engineering, operations, and commercial development in the midstream and E&P industries. Immediately prior to joining Crosstex, Mr. Golemon held various midstream engineering, commercial, and management positions with Union Pacific Resources and its successor company Anadarko Petroleum Corporation. Mr. Golemon also spent 3 years with The Arrington Corporation consulting on sulfur recovery operations and Process Safety Management. Mr. Golemon began his career with ARCO Oil and Gas Company where he worked in plant, onshore facilities, and offshore facilities engineering. Mr. Golemon graduated summa cum laude from Louisiana Tech University in 1985 with a Bachelor of Science degree in Chemical Engineering.

Rhys J. Best joined Crosstex Energy GP, LLC as a director in June 2004 and became Chairman of the Board in February 2009. Mr. Best was Chairman and Chief Executive Officer of Lone Star Technologies, Inc., until its merger into United States Steel Company in June of 2007. Mr. Best held the position of Chief Executive Officer from June 1998 and he assumed the additional responsibilities of Chairman in January 1999. He began his career at Lone Star as the President and Chief Executive Officer of Lone Star Steel Company, a position he held for eight years before becoming President and Chief Operating Officer of the parent company in 1997. Before joining Lone Star, Mr. Best held several leadership positions in the banking industry. Mr. Best also serves on the boards of Trinity Industries (NYSE: TRN), Cabot Oil & Gas Corp. (NYSE: COG), Commercial Metals Company (NYSE:CMC), Austin Industries, Inc., and McJunkin Red Man Corporation. Trinity is a leading diversified holding company with a subsidiary group that provides a variety of products and services for the transportation, industrial, construction and energy sectors. Cabot is an oil and gas exploration and production company. Commercial Metals Company manufactures, recycles and markets steel, other metals and related products. Austin Industries and McJunkin Red Man are private companies in the construction and energy sectors. Mr. Best graduated from the University of North Texas with a Bachelor of Business degree and later earned a Masters of Business Administration degree at Southern Methodist University. Mr. Best's experience in the financial sector and pipe manufacturing industry, leadership skills and experience as Chairman and Chief Executive Officer of public companies, among other factors, led the Board to conclude that he should serve as a director.

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

Bryan H. Lawrence, joined Crosstex Energy GP, LLC as a director upon the completion of our initial public offering in December 2002 and served as Chairman of the Board until May 2008. Mr. Lawrence is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships, which make investments in companies engaged in the energy industry. The Yorktown partnerships were formerly affiliated with the investment firm of Dillon, Read & Co. Inc., where Mr. Lawrence had been employed since 1966, serving as a Managing Director until the merger of Dillon Read with SBC Warburg in September 1997. Mr. Lawrence also serves as a director of Hallador Petroleum Company (OTC BB: HPCO.OB), Star Gas Partners L.P. (NYSE: SGU), Winstar Resources Ltd. (a Canadian public company), Approach Resources, Inc. (NASDAQ: AREX) and certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests. Mr. Lawrence is a graduate of Hamilton College and also has an M.B.A. from Columbia University. Mr. Lawrence has also served as a director of Crosstex Energy, Inc. since 2000. Mr. Lawrence's financial and investment experience, and experience in the energy industry, among other factors, led the Board to conclude that he should serve as a director.

Sheldon B. Lubar joined Crosstex Energy GP, LLC as a director upon the completion of our initial public offering in December 2002. Mr. Lubar has been Chairman of the Board of Lubar & Co. Incorporated, a private investment and venture capital firm he founded, since 1977. He was Chairman of the Board of Christiana Companies, Inc., a logistics and manufacturing company, from 1987 until its merger with Weatherford International in 1995 and also served as a director of Weatherford International, Inc. (NYSE: WFT) until 2008. Mr. Lubar also served as Chairman and a director of Total Logistics, Inc. until its merger with Super Value Companies (NYSE: SVU) in 2005. Mr. Lubar also serves as a director of Hallador Petroleum Company (OTC BB: HPCO.OB), Star Gas Partners L.P. (NYSE: SGU) and Approach Resources, Inc. (NASDAQ: AREX), an oil and gas exploration and production company. Mr. Lubar holds a bachelor's degree in Business Administration and a law degree from the University of Wisconsin—Madison. He was awarded an honorary Doctor of Commercial Science degree from the University of Wisconsin—Milwaukee in 1988 and a Doctor of Humanities degree from the University of Wisconsin—Madison in 2009. Mr. Lubar has also served as a director of Crosstex Energy, Inc. since January 2004. Mr. Lubar's investment experience, industry experience and service on other public company boards, among other factors, led the Board to conclude that he should serve as a director.

Cecil E. Martin, Jr., joined Crosstex Energy GP, LLC as a director in January 2006. He has been an independent residential and commercial real estate investor since 1991. From 1973 to 1991 he served as chairman of the public accounting firm Martin, Dolan and Holton in Richmond, Virginia. He began his career as an auditor at Ernst and Ernst. He holds a B.B.A. degree from Old Dominion University and is a Certified Public Accountant. Mr. Martin also serves on the board and as chairman of the audit committee for Comstock Resources, Inc. (NYSE: CRK), an independent energy company engaged in oil and gas acquisitions, exploration and development. Mr. Martin served on the board and as chairman of the audit committee for Bois d'Arc Energy, Inc. (NYSE: BDE) until its merger into Stone Energy Corporation, (NYSE: SGY) in 2008. Mr. Martin also has served as a director of Crosstex Energy, Inc. since January 2006. Mr. Martin's accounting and financial experience, experience on audit committees of other public companies, and related industry experience, among other factors, led the Board to conclude that he should serve as a director.

Donald (Dwight) Scott joined Crosstex Energy GP, LLC as a director in January 2010. He is a Senior Managing Director of GSO Capital Partners LP and head of GSO's Houston Office. Mr. Scott focuses on investments in the energy and power markets and is a member of GSO's Investment Committee. Before joining GSO in 2005, Mr. Scott was an Executive Vice President and Chief Financial Officer of El Paso Corporation (NYSE: EP). Prior to joining El Paso, Mr. Scott served as a managing director in the energy investment banking practice of Donaldson, Lufkin & Jenrette. Mr. Scott earned a BA from the University of North Carolina at Chapel Hill and a MBA from The University of Texas at Austin. He is currently a Director of Cheniere Energy, Inc. (AMEX: LNG), Crestwood Midstream Partners, MCV Investors, Inc., SandRidge Energy, Inc. (NYSE: SD) and United Engines Holding Company, LLC. Mr. Scott is a member of the Board of Trustees of KIPP, Inc. and the River Oaks Baptist School. Mr. Scott brings to the Board investment, financial and industry experience. Mr. Scott was selected as a director pursuant to a Board Representation Agreement entered into on January 19, 2010 between us, our general partner, Crosstex Energy GP, LLC, CEI and GSO Crosstex Holdings LLC. Pursuant to the Board Representation Agreement, each of the Crosstex entities agreed to take all actions necessary or advisable to cause one director serving on the Board to be designated by GSO Crosstex Holdings LLC, in its sole discretion.

Kyle D. Vann joined Crosstex Energy GP, LLC as a director in April 2006. Mr. Vann began his career with Exxon Corporation in 1969. After ten years at Exxon, he joined Koch Industries and served in various leadership capacities, including senior vice president from 1995 to 2000. In 2001, he then took on the role of CEO of Entergy-Koch, LP, an energy trading and transportation company, which was sold in 2004. Currently, Mr. Vann, who is retired, continues to consult with Entergy and Texon, L.P. He also serves on the boards of Texon, L.P. and Legacy Reserves, LLC and on the Advisory Board for Haddington Ventures, LLC, and will serve on the board of Enexus Energy Corporation if its spin-off from Entergy is approved. Mr. Vann graduated from the University of Kansas with a Bachelor of Science degree in chemical engineering. He is a member of the Board of Advisors for the University of Kansas School of Engineering. Mr. Vann serves on the board of various charitable organizations. Mr. Vann's industry experience, and leadership roles in the energy trading and transportation businesses, among other factors, led the Board to conclude that he should serve as a director.

Independent Directors

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

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

Board Committees

The board of directors of Crosstex Energy GP, LLC, has, and appoints the members of, standing Audit, Compensation, Governance and Conflicts Committees. Each member of the Audit, Compensation, Governance and Conflicts Committees is an independent director in accordance with NASDAQ standards described above. Each of the board committees has a written charter approved by the board. Copies of the charters are available to any person, free of charge, at our web site: www.crosstexenergy.com.

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

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

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

The Governance Committee, comprised of Mr. Lubar (chair), reviews matters involving governance including assessing the effectiveness of current policies, monitoring industry developments, recommending committee structures within the Board, managing the assessment process of the Board and individual directors, annually reviewing and recommending the compensation of directors and performing other duties as delegated from time to time. The Committee is responsible for identifying board candidates and making recommendations to the board of directors regarding the election of directors. When board vacancies are created or occur, the Committee reviews applicable legal requirements, listing requirements, and the competencies of the continuing directors, and develops a candidate profile that identifies any specific competencies or expertise that the Committee believes the board of directors needs to add or supplement. The Committee solicits referrals from existing directors and other industry contacts to identify candidates that possess those specific competencies or that specific expertise. In the past, the Committee has also used search firms to identify potential candidates. The Committee then interviews interested candidates to assess the candidate's qualifications and to assess the ability of the candidate to work with the other directors. The Committee evaluates candidates and makes its recommendations on the basis of the qualifications of each candidate individually, including the candidate's reputation, professional experience, experience in the same or related industries, service on other public company boards, other time commitments, the diversity of the board members' backgrounds and professional experience, and the ability of the candidate to work with other board members. Under the terms of our partnership agreement, unitholders do not participate in the appointment or election of the directors of Crosstex Energy GP, LLC.

Code of Ethics

Crosstex Energy GP, LLC, has adopted a Code of Business Conduct and Ethics (the "Code of Ethics") applicable to all of our employees, officers and directors with regard to Partnership-related activities. The Code of Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. It also incorporates expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. A copy of the Code of Ethics is available to any person, free of charge, at our web site www.crosstexenergy.com. If any substantive amendments are made to the Code of Ethics or if we or Crosstex Energy GP, LLC grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to any of our general partner's executive officers and directors, we will disclose the nature of such amendment or waiver on our web site.

Section 16(a) — Beneficial Ownership Reporting Compliance

Based on our records, except as set forth below, we believe that during 2009 all reporting persons complied with the Section 16(a) filing requirements applicable to them. Due to administrative errors, Form 4s were filed late on behalf of Susan J. McAden regarding grants of restricted units by Crosstex Energy, L.P. under the company's long-term incentive plan on June 10, 2008, April 1, July 1 and December 1, 2009 and regarding an exchange of unit options on June 11, 2009, and Barry E. Davis regarding security purchases on March 10, 2009 and Form 3s were filed late on behalf of Michael J. Garberding and Stan Golemon following the determination that such persons are named executive officers.

Reimbursement of Expenses of our General Partner and its Affiliates

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

Item 11. *Executive Compensation*

We do not directly employ any of the persons responsible for managing our business. Crosstex Energy GP, LLC, the general partner of our general partner, manages our operations and activities, and its board of directors and officers make decisions on our behalf. The compensation of the executive officers of Crosstex Energy GP, LLC is determined by the board of directors of Crosstex Energy GP, LLC upon the recommendation of its Compensation Committee. The compensation of the directors of Crosstex Energy GP, LLC is determined by the board of directors of Crosstex Energy GP, LLC upon the recommendation of its Governance Committee. Our named executive officers also serve as officers of Crosstex Energy, Inc. and the compensation of the named executive officers discussed below reflects total compensation for services to all Crosstex entities. We pay or reimburse all expenses incurred on our behalf, including the costs of employee, officer and director compensation and benefits, as well as all other expenses necessary or appropriate to the conduct of our business. Our partnership agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Crosstex Energy, Inc. currently pays a monthly fee to us to cover its portion of administrative and compensation costs, including compensation costs relating to the named executive officers.

Based on the information that we track regarding the amount of time spent by each of our named executive officers on business matters relating to Crosstex Energy, L.P., we estimate that such officers devoted the following percentage of their time to the business of Crosstex Energy, L.P. and to Crosstex Energy, Inc., respectively, for 2009:

Executive Officer or Director	Percentage of Time Devoted to Business of Crosstex Energy, L.P.	Percentage of Time Devoted to Business of Crosstex Energy, Inc.
Barry E. Davis	83%	17%
William W. Davis	74%	26%
Joe A. Davis	88%	12%
Michael J. Garberding	94%	6%
Stan Golemon	100%	—

Compensation Committee Report

Each member of Crosstex Energy GP, LLC's Compensation Committee is an independent director in accordance with NASDAQ standards. The Committee has reviewed and discussed with management the following section titled "Compensation Discussion and Analysis." Based upon its review and discussions, the Committee has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Cecil E. Martin (Chairman)
Rhys J. Best

Compensation Discussion and Analysis

The Charter of the Compensation Committee of the Board of Directors of Crosstex Energy GP, LLC, includes the following:

- The Committee has general oversight responsibility for the Company's compensation plans, policies and programs. This general oversight responsibility includes reviewing and approving compensation policies and practices for all employees, overall payroll, bonus plans, overall bonus payouts, setting bonus targets, and other general compensation matters.

- Not less than annually, the Committee will review the Company's executive compensation plans and policies. The Committee will review the corporate goals and objectives relevant to the compensation of the Chief Executive Officer, the other executive officers, and each other senior officer that the Committee or the Board may designate (collectively referred to as the "Executive Officers"). The Committee will evaluate the performance of the Chief Executive Officer, and together with the Chief Executive Officer, the performance of each other Executive Officer. The Committee will at least annually review each Executive Officer's base compensation, bonus, awards under the Company's Long Term Incentive Plans, and any other compensation, and make recommendations to the Board regarding each Executive Officer's compensation.

- The Committee will review and approve the terms of any employment contracts, severance agreements, or other contracts with any Executive Officer, provided that the Board reserves to itself the approval of the compensation of the Executive Officers.

In order to compete effectively in our industry, it is critical that we attract, retain and motivate leaders that are best positioned to deliver financial and operational results that benefit our unitholders. It is the Committee's responsibility to design and administer compensation programs that achieve these goals, and to make recommendations to the Board of Directors to approve and adopt these programs.

Compensation Philosophy and Principles.

Our executive compensation is designed to attract, retain and motivate top-tier executives, and align their individual interests with the interests of the unitholders. The compensation of each of our executives is comprised of base salary, bonus opportunity and restricted equity grants or option awards under long term incentive plans. The Committee's philosophy is to generally target the 50th percentile of our Peer Group (discussed below) for base salaries, target the 50th percentile of our Peer Group for bonuses (but retain discretion to reduce or increase bonus amounts to address individual performance), and to provide executives the opportunity to earn long-term compensation, in the form of equity, in the top quartile relative to our Peer Group.

The Committee considers the following principles in determining the total compensation of the named executive officers:

- in order to achieve its goals, it is critical that we attract, retain and motivate highly qualified executive officers;

- base salary and bonus opportunities must be competitive in order to attract, retain and motivate highly qualified executive officers;
- equity incentive compensation should represent a significant portion of the executive's total compensation in order to retain and incentivize highly qualified executives, and align their individual long term interests with the interests of unitholders;
- compensation programs must be sufficiently flexible to address special circumstances, which have included payments under retention plans specifically targeted to retain highly qualified officers during challenging times; and
- the overall compensation program should drive performance and reward contributions in support of our business strategies and achievements.

Compensation Methodology.

Annually, the Committee reviews our executive compensation program in total and each element of compensation specifically. The review includes an analysis of the compensation practices of other companies in our industry, the competitive market for executive talent, the evolving demands of the business, specific challenges that we may face, and individual contributions to our partnership. The Committee recommends to the Board adjustments to the overall compensation program and to its individual components as the Committee determines necessary to achieve our goals. The Committee periodically retains consultants to assist in its review and to provide input regarding its compensation program and each of its elements.

In 2009, the Committee retained BDO Seidmann, LLC ("BDO") as its independent compensation consultant to conduct a compensation review and advise the Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees of Crosstex Energy GP, LLC. BDO provided a report and presentation to the Committee regarding the compensation programs of the Crosstex entities dated June 17, 2009.

With respect to compensation objectives and decisions regarding the named executive officers for fiscal 2009, the Committee has reviewed market data with respect to peer companies provided by BDO in determining relevant compensation levels and compensation program elements for our named executive officers, including establishing their respective base salaries. In addition, BDO has also provided guidance on current industry best practices to the committee. During 2009 Mercer Human Resource Consulting also provided the Committee with data that it utilized in evaluating its compensation policies. The market data that we reviewed included the base salaries paid to executive officers in similar positions at our peer companies, as well as a comparison of the mix of total compensation (including base salary, bonus structure, bonus methodology and short and long-term compensation elements) paid to executive officers in similar positions at such companies. For 2009, we identified the following companies as "Peer Companies" for comparison purposes: Energy Transfer Partners, L.P., Enbridge Energy Partners, L.P., ONEOK Partners, L.P., Southern Union, Magellan Midstream Holdings, L.P., NuStar Energy, L.P., Copano Energy, LLC, Regency Energy Partners, L.P., MarkWest Energy Partners, L.P., Boardwalk Pipeline Partners, L.P., Atmos Energy Corporation, El Paso Corporation, Questar Corporation, EQT Corporation, Pioneer Natural Resources Company, Plains Exploration & Production Company, Cabot Oil & Gas Corporation, St. Mary Land & Exploration Company and Range Resources Corporation. We believe that this group of companies is representative of the industry in which we operate and the individual companies were chosen because of such companies' relative position in our industry, their relative size/market capitalization, the relative complexity of the business, similar organizational structure, competition for similar executive talent, and the named executive officers' roles and responsibilities.

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

Elements of Compensation.

The primary elements of Crosstex Energy GP, LLC's compensation program are a combination of annual cash and long-term equity-based compensation. For fiscal year 2009, the principal elements of compensation for the named executive officers were the following:

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

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

Base Salary. The Committee recommends base salaries for the named executive officers based on the historical salaries for services rendered to Crosstex Energy GP, LLC and its affiliates, market data and responsibilities of the named executive officers. Salaries are generally determined by considering the employee's performance and prevailing levels of compensation in areas in which a particular employee works. As discussed above, except with respect to the monthly reimbursement payment received from Crosstex Energy, Inc., all of the base salaries of the named executive officers were allocated to us by Crosstex Energy GP, LLC as general and administration expenses. The base salaries paid to our named executive officers during fiscal year 2009 are shown in the Summary Compensation Table on page 81. We did not make any adjustments in the base salaries of our named executive officers in 2009. Effective January 1, 2010, the base salaries payable to our named executive officers were adjusted to equal the following: Barry E. Davis $435,000, William W. Davis $330,000; Joe A. Davis $300,000; Stan Golemon $230,000 and Michael Garberding $215,000.

Bonuses and Annual Cash Bonus Plan Awards. The Committee oversees the Annual Cash Bonus Plan and makes recommendations regarding cash bonuses to be awarded to each of the named executive officers. The Annual Cash Bonus Plan is applicable to all employees. Under the plan, bonuses are awarded to our named executive officers based on a formulaic approach that is initially determined using a performance metric tied to Adjusted EBITDA (see page 5 for definition). The same adjusted EBITDA performance metric is used for bonuses for all employees. The adjusted EBITDA goals are determined at the beginning of the year by the board of directors of Crosstex Energy GP, LLC, upon the recommendation of the Committee. Discretionary bonuses in addition to bonuses under the Annual Cash Bonus Plan are awarded from time to time by the Committee to reward outstanding service to the Company.

Approximately two-thirds of the bonuses calculated under the formula applicable to each of our named executive officers for fiscal 2009 are strictly formulaic and nondiscretionary. The remaining one-third of the amount determined by the formula is at the discretion of the Committee, based upon the Committee's assessment of the executive's meeting his or her performance objectives established at the beginning of the performance period. These performance objectives include the quality of leadership within the named executive officer's assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer and the named executive officer's contribution to, and enhancement of, the desired company culture. These performance objectives are reviewed and evaluated by our Committee as a whole. All of our named executive officers met or exceeded their personal performance objectives for 2009.

The Committee believes that a portion of executive compensation must remain discretionary, and exercises its discretion with respect to a portion of the cash bonus awards payable to its named executive officers. The Committee may exercise its discretion to reduce the amount calculated under the formula as described above, or to supplement the amount to reward or address extraordinary individual performance, challenges and opportunities not reasonably foreseeable at the beginning of a performance period, internal equities, and external competition or opportunities.

Target adjusted EBITDA is based upon a standard of reasonable market expectations and company performance, and varies from year to year. Several factors are reviewed in determining target adjusted EBITDA, including market expectations, internal forecasts and available investment opportunities. For 2009, our targets for bonuses, after adjustments to account for the effects of discontinued operations and certain other adjustments, were $185.5 million for minimum bonuses, $203.5 million for mid-point bonuses and $252.5 million for maximum bonuses. The 2009 plan provided for named executive officers to receive bonus payouts of 10% at the minimum threshold, payouts ranging from 35% to 90% at the mid-point target and maximum payouts ranging from 60% to 180% of an executive officer's base salary. We met the target for mid-point bonuses in 2009.

For 2010, the Board has approved a continuation of the Annual Cash Bonus Plan with adjusted EBITDA as the performance metric. Under the 2010 plan, bonuses will be determined based on adjusted EBITDA levels ranging from a threshold of $165.0 million to a maximum of $210.0 million, with a mid-point adjusted EBITDA of $185.0 million.

The Board has also approved payments to our named executive officers and certain other senior executives and key leaders under a Key Employee Retention Plan for 2009 and the first six months of 2010. Under the 2009 plan, Barry E. Davis, William W. Davis and Joe A. Davis received retention payments in quarterly installments equal to 20% of base salary for the first three quarters of the year and 40% of base salary for the fourth quarter, and Stan Golemon and Michael J. Garberding received retention payments in quarterly installments equal to 12% of base salary for the first three quarters of the year and 24% of base salary for the fourth quarter. Under the 2010 plan, participants will receive quarterly retention payments equal to 20% of base salary for each of the first two quarters of the year, provided that the participant is employed by our partnership at the time of payment. In the case of a participant who is terminated by us without cause, such participant will receive a prorated payment based on time of employment. Payments made under the Key Employee Retention Plan are credited against payments that would otherwise be payable to a participant under the Annual Cash Bonus Plan. The Key Employee Retention Plan is designed to retain and incentivize employees that are very important for the accomplishment of the Partnership's objectives during critical times. Participation in the plan is at the discretion of the Committee and the Board.

Long-Term Incentive Plans. Our officers and directors are eligible to participate in long-term incentive plans adopted by each of Crosstex Energy GP, LLC and Crosstex Energy, Inc. We believe that equity awards are instrumental in attracting, retaining, and motivating employees, and align the interests of our officers and directors with the interests of the unitholders. The board of directors of Crosstex Energy GP, LLC, at the recommendation of the Committee, approves the grants of Partnership units or options to our executive officers. The Committee believes that equity compensation should comprise a significant portion of a named executive officer's compensation, and considers a number of factors when determining the grants to each individual. The considerations include: the general goal of allowing the named executive officer the opportunity to earn aggregate equity compensation (comprised of Partnership units and Crosstex Energy, Inc. stock) in the upper quartile of our Peer Group; the amount of unvested equity held by the individual executive; the executive's performance; and other factors as determined by the Committee.

A discussion of each plan follows:

Crosstex Energy GP, LLC Long-Term Incentive Plan. Crosstex Energy GP, LLC has adopted a long-term incentive plan for employees and directors of Crosstex Energy GP, LLC and its affiliates who perform services for us. The long-term incentive plan is administered by the Committee and permits the grant of awards covering an aggregate of 5,600,000 common units, which may be awarded in the form of restricted units or unit options. Of the 5,600,000 common units that may be awarded under the long-term incentive plan, 1,401,982 common units remain eligible for future grants by Crosstex Energy GP, LLC as of January 1, 2010. The long-term compensation structure is intended to align the employee's performance with long-term performance for our unitholders.

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

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

- *Restricted Units.* A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. In the future, the Committee may make grants under the plan to employees and directors containing such terms as it shall determine under the plan. The Committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted units will vest upon a change of control of us or of our general partner, as discussed below under "— Potential Payments Upon a Change of Control or Termination." Common units to be delivered upon the vesting of restricted units may be common units acquired by Crosstex Energy GP, LLC in the open market, common units already owned by Crosstex Energy GP, LLC, common units acquired by Crosstex Energy GP, LLC directly from us or any other person or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. The Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units which entitles the grantee to distributions attributable to the restricted units prior to vesting of such units. We intend the issuance of the common units upon vesting of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under current policy, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

- *Performance Units.* A performance unit represents a contractual commitment to grant restricted units in the future if certain conditions are satisfied. In the past performance unit agreements have only been entered into with members of our senior management. We did not grant any performance unit agreements in 2009. Under the terms of past performance unit agreements, to be eligible to receive the restricted units, the executive officer must continuously be employed from the date of the agreement through January 1 of the third calendar year following such date, and no units will be credited to an award recipient under our long term incentive plan until such future date. Each agreement provides for a target number of units that are to be granted in the future. As of March 1, 2010, only performance units granted in 2008 remain outstanding. Under the 2008 grant, the target number of units will be increased (up to a maximum of 300% of the target number of units) or decreased (to a minimum of 30% of the target number of units) based on Crosstex Energy, L.P.'s average growth rate (defined as the percentage increase or decrease in distributable cash flow per unit) compared to the target growth rate of 9.0%. The restricted units that are granted pursuant to the 2008 performance unit agreements will vest and become unrestricted as of March 1, 2011 if the executive officer remains an employee through such date. The performance units granted in 2007 that did not lapse vested at the minimum amount of 30% of the target number of units and became unrestricted units as of March 1, 2010.

The total value of the equity compensation granted to our named executive officers generally has been allocated 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. For fiscal year 2009, Crosstex Energy GP, LLC granted 104,167, 91,667, 91,667, 29,167 and 41,667 restricted units to Barry E. Davis, William W. Davis, Joe A. Davis, Michael J. Garberding, and Stan Golemon, respectively. All performance and restricted units that we grant are charged against earnings according to FASB ASC 718.

Crosstex Energy, Inc. Long-Term Incentive Plans. The Crosstex Energy, Inc. long-term incentive plans provide for the award of stock options and restricted stock (collectively, "Awards") for up to 7,190,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2010, approximately 2,230,800 shares remained available under the long-term incentive plans for future issuance to participants. A participant may not receive in any calendar year options relating to more than 250,000 shares of common stock. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Shares of common stock underlying Awards that are forfeited, terminated or expire unexercised become immediately available for additional Awards under the long-term incentive plan.

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

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

- *Stock Options.* Stock options are rights to purchase a specified number of shares of common stock at a specified price. An option granted pursuant to the plan may consist of either an incentive stock option that complies with the requirements of section 422 of the Code, or a nonqualified stock option that does not comply with such requirements. Only employees may receive incentive stock options and such options must have an exercise price per share that is not less than 100% of the fair market value of the common stock underlying the option on the date of grant. Nonqualified stock options also must have an exercise price per share that is not less than the fair market value of the common stock underlying the option on the date of grant. The exercise price of an option must be paid in full at the time an option is exercised.

- *Restricted Stock Awards.* Stock awards consist of restricted shares of common stock of Crosstex Energy, Inc. The Compensation Committee of Crosstex Energy, Inc. will determine the terms, conditions and limitations applicable to any restricted stock awards. Rights to dividends or dividend equivalents may be extended to and made part of any stock award at the discretion of the Crosstex Energy, Inc. Compensation Committee. Restricted stock awards will have a vesting period established in the sole discretion of the Compensation Committee, provided that the Compensation Committee may provide for earlier vesting by reason of death, disability, retirement or otherwise.

- *Performance Shares.* A performance share represents a contractual commitment to grant restricted shares in the future if certain conditions are satisfied. In the past, performance share agreements have only been entered into with members of our senior management. We did not grant any performance share agreements in 2009. Under the terms of past performance share agreements, to be eligible to receive the restricted shares, the executive officer must continuously be employed from the date of the agreement through January 1 of the third calendar year following such date, and no shares will be credited to an award recipient under our long term incentive plan until such future date. Each agreement provides for a target number of shares that are to be granted in the future. As of March 1, 2010, only performance shares granted in 2008 remain outstanding. Under the 2008 grant, the target number of shares will be increased (up to a maximum of 300% of the target number of shares) or decreased (to a minimum of 30% of the target number of shares) based on Crosstex Energy, L.P.'s average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit) compared to the target growth rate of 9%. The restricted shares that are granted pursuant to the 2008 performance share agreements will vest and become unrestricted as of March 1, 2011 if the executive officer remains an employee through such date. The performance shares granted in 2007 that did not lapse vested at the minimum amount of 30% of the target number of units and became unrestricted units as of March 1, 2010.

Crosstex Energy, Inc.'s board of directors may amend, modify, suspend or terminate the long-term incentive plans for the purpose of addressing any changes in legal requirements or for any other purpose permitted by law, except that no amendment that would impair the rights of any participant to any Award may be made without the consent of such participant, and no amendment requiring stockholder approval under any applicable legal requirements will be effective until such approval has been obtained. No incentive stock options may be granted after the tenth anniversary of the effective date of the plan.

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

The total value of the equity compensation granted to our executive officers generally has been awarded 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2009, Crosstex Energy, Inc. granted 104,167, 91,667, 91,667, 29,167 and 41,667 restricted shares to Barry E. Davis, William W. Davis, Joe A. Davis, Michael J. Garberding, and Stan Golemon, respectively. All performance and restricted shares that we grant are charged against earnings according to FASB ASC 718.

Retirement and Health Benefits. Crosstex Energy GP, LLC offers a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are generally eligible for the same programs on the same basis as other employees of Crosstex Energy GP, LLC. Crosstex Energy GP, LLC maintains a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax deferred basis. In 2009, Crosstex Energy GP, LLC matched 100% of every dollar contributed for contributions of up to 6% of salary (not to exceed the maximum amount permitted by law) made by eligible participants. The retirement benefits provided to the named executive officers were allocated to us as general and administration expenses. Our executive officers are also eligible to participate in any additional retirement and health benefits available to our other employees.

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

Employment and Severance Agreements

Barry E. Davis, William W. Davis, and Joe A. Davis have entered into employment agreements with Crosstex Energy GP, LLC. All of these employment agreements are substantially similar. Each of the employment agreements has a term of one year that will automatically be extended such that the remaining term of the agreements will not be less than one year. The employment agreements include obligations not to disclose confidential information and also provide for a noncompetition period that will continue for one year after the termination of the employee's employment or the date on which the employee is no longer entitled to receive payments under the employment agreement. During the noncompetition period, the employees are generally prohibited from engaging in any business that competes with us or our affiliates in areas in which we conduct business as of the date of termination and from soliciting or inducing any of our employees to terminate their employment with us.

Stan Golemon and Michael Garberding have entered into Severance Agreements with Crosstex Energy GP, LLC. These agreements are substantially similar and provide for severance payable to the employee if their employment is terminated without cause before December 31, 2010 or in the event of a change in control (as defined in the Severance Agreements). Crosstex Energy GP, LLC has entered into similar Severance Agreements with other senior management and certain other key leaders.

Potential Payments Upon a Change of Control or Termination.

Under the employment and severance agreements with our named executive officers, we may be required to pay certain amounts upon a change of control of us or our affiliates or upon the termination of the executive officer in certain circumstances. Except in the event of our becoming bankrupt or ceasing operations, termination for cause or termination by the employee other than for good reason, or if a change in control occurs during the term of an employee's employment and either party to the agreement terminates the employee's employment as a result thereof, the employment and severance agreements entered into between Crosstex Energy GP, LLC and each of the named executive officers provide for continued salary payments, accrued bonuses and benefits following termination of employment for the one year period following termination. The terms contained in the employment and severance agreements were established at the time we entered into such agreements with our named executive officers. These terms were determined based on past practice and our understanding of similar agreements utilized by public companies generally at the time we entered into such agreements. The determination of the reasonable consequences of a change of control is periodically reviewed by the Committee. For purposes of the employment and severance agreements:

- "Cause" means that:
  - the employee has failed to perform the duties assigned to him and such failure has continued for 30 days following delivery by Crosstex Energy GP, LLC of written notice to the employee of such failure;
  - the employee has been convicted of a felony or misdemeanor involving moral turpitude;
  - the employee has engaged in acts or omissions against Crosstex Energy GP, LLC constituting dishonesty, breach of fiduciary obligation or intentional wrongdoing or misfeasance;
  - the employee has acted intentionally or in bad faith in a manner that results in a material detriment to the assets, business or prospects of Crosstex Energy GP, LLC; or
  - the employee has breached any obligation under the employment agreement, if applicable.
- "Good Reason" includes any of the following:
  - the assignment to employee of any duties materially inconsistent with the employee's position (including a materially adverse change in the employee's office, title and reporting requirements), authority, duty or responsibilities;
  - Crosstex Energy GP, LLC requiring the employee to be based at any office other than the offices in the greater Dallas, Texas area;
  - regarding the severance agreements, any reduction in the employee's base salary; and

- regarding the employment agreements, any termination by Crosstex Energy GP, LLC of the employee's employment other than as expressly permitted by the employment agreement, or a breach or violation by Crosstex Energy GP, LLC of any material provision of the employment agreement, which breach or violation remains unremedied for more than 30 days after written notice thereof is given to Crosstex Energy GP, LLC by the employee.

No act or failure to act on Crosstex Energy GP, LLC's part shall be considered "good reason" unless the employee has given Crosstex Energy GP, LLC written notice of such act or failure to act within 30 days thereof and Crosstex Energy GP, LLC fails to remedy such act or failure to act within 30 days of its receipt of such notice.

- A "change in control" shall be deemed to have occurred -

  - under the employment agreements, (i) if Crosstex Energy, Inc. and/or its affiliates, collectively, no longer directly or indirectly hold a controlling interest in Crosstex Energy GP, L.P. or Crosstex Energy GP, LLC and the named executive officer does not remain employed by Crosstex Energy GP, LLC upon the occurrence of such event (whether the employee's employment is terminated voluntarily or by Crosstex Energy GP, LLC); (ii) upon the consummation of any transaction as a result of which any person (other than Yorktown Partners LLC, or its affiliates including any funds under its management) becomes the "beneficial owner" (as defined in Rule 13d-3 under the Securities Exchange Act of 1934, as amended), directly or indirectly, of at least 50% of the total voting power represented by the outstanding voting securities of Crosstex Energy, Inc. at a time when Crosstex Energy, Inc. still beneficially owns 50% or more of the voting power of the outstanding equity interests of Crosstex Energy GP, L.P. or Crosstex Energy GP, LLC; or (iii) Crosstex Energy GP, LLC has caused the sale of at least 50% of our assets; or

  - under the severance agreements, if (i) a person or group of persons acting together acquire more than 50% of the currently issued and outstanding equity securities of Crosstex Energy Inc. in one transaction or a series of transactions (provided, however, that Crosstex Energy Inc.'s issuance of additional equity securities to a person or persons that, after such issuance, comprise more than 50% of the issued and outstanding equity securities of Crosstex Energy, Inc. is not a "Change in Control"); (ii) individuals who constitute the Board of Directors of Crosstex Energy, Inc. (the "Board") as of the date of the severance agreement (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board (provided, however, that any individual becoming a director subsequent to the date of the agreement whose election by the Board was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual was a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an election contest with respect to the election or removal of directors or other solicitation of proxies or consents by or on behalf of a person other than the Board); or (iii) all or substantially all of our assets have been sold, transferred or are otherwise owned by an entity that is not directly or indirectly controlled or governed by Crosstex Energy, Inc.

If a termination of a named executive officer by Crosstex Energy GP, LLC other than for cause, a termination by a named executive officer for good reason or upon a change in control were to have occurred as of December 31, 2009, our named executive officers would have been entitled to the following:

- Barry E. Davis would have received $435,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $391,500 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control (less any advance bonus payments previously made), and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;

- William W. Davis would have received $315,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $204,750 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control (less any advance bonus payments previously made), and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;

- Joe A. Davis would have received $285,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $185,250 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control (less any advance bonus payments previously made), and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;

- Michael J. Garberding would have received $198,000 representing one year base salary (paid in a lump sum), $69,300 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control (less any advance bonus payments previously made), and an amount equal to his cost under COBRA to extend medical insurance benefits for a period of one year; and

- Stan Golemon would have received $220,000 representing one year base salary (paid in a lump sum), $77,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control (less any advance bonus payments previously made), and an amount equal to his cost under COBRA to extend medical insurance benefits for a period of one year.

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

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

For purposes of the long-term incentive plan, a "change in control" means, and shall be deemed to have occurred upon: (i) the consummation of a merger or consolidation of Crosstex Energy GP, LLC with or into another entity or any other transaction if persons who were not holders of equity interests of Crosstex Energy GP, LLC immediately prior to such merger, consolidation or other transaction, own 50% or more of the voting power of the outstanding equity interests of the continuing or surviving entity; (ii) the sale, transfer or other disposition of all or substantially all of Crosstex Energy GP, LLC's or our assets; (iii) a change in the composition of the board of directors as a result of which fewer than 50% of the incumbent directors are directors who either had been directors of Crosstex Energy GP, LLC on the date 12 months prior to the date of the event that may constitute a change in control (the "original directors") or were elected, or nominated for election, to the board of directors of Crosstex Energy GP, LLC with the affirmative votes of at least a majority of the aggregate of the original directors who were still in office at the time of the election or nomination and the directors whose election or nomination was previously so approved; or (iv) the consummation of any transaction as a result of which any person (other than Yorktown Partners LLC, or its affiliates including any funds under its management) becomes the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of Crosstex Energy, Inc. representing at least 50% of the total voting power represented by Crosstex Energy, Inc.'s then outstanding voting securities at a time when Crosstex Energy, Inc. still beneficially owns more than 50% of securities of Crosstex Energy GP, LLC representing at least 50% of the total voting power represented by Crosstex Energy GP, LLC's then outstanding voting securities.

If a change in control were to have occurred as of December 31, 2009, unit options, restricted units and performance units held by the named executive officers would have automatically vested and become payable or exercisable, as follows:

- Barry E. Davis held 104,167 restricted units and 218,120 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control;

- William W. Davis held 91,667 restricted units and 105,318 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control;.

- Joe A. Davis held 91,667 restricted units and 91,876 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control;

- Michael J. Garberding held 34,494 restricted units that would have become fully vested, payable and/or exercisable as a result of such change in control; and

- Stan Golemon held 48,607 restricted units that would have become fully vested, payable and/or exercisable as a result of such change in control.

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

For purposes of the long-term incentive plans, a "change of control" means: (i) the consummation of a merger or consolidation of Crosstex Energy, Inc. with or into another entity or any other transaction, if persons who were not shareholders of Crosstex Energy, Inc. immediately prior to such merger, consolidation or other transaction beneficially own immediately after such merger, consolidation or other transaction 50% or more of the voting power of the outstanding securities of each of (a) the continuing or surviving entity and (b) any direct or indirect parent entity of such continuing or surviving entity; (ii) the sale, transfer or other disposition of all or substantially all of Crosstex Energy, Inc.'s assets; (iii) a change in the composition of the board of directors of Crosstex Energy, Inc. as a result of which fewer than 50% of the incumbent directors are directors who either (a) had been directors of Crosstex Energy, Inc. on the date 12 months prior to the date of the event that may constitute a change of control (the "original directors") or (b) were elected, or nominated for election, to the board of directors of Crosstex Energy, Inc. with the affirmative votes of at least a majority of the aggregate of the original directors who were still in office at the time of the election or nomination and the directors whose election or nomination was previously so approved; or (iv) any transaction as a result of which any person is the "beneficial owner" (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of Crosstex Energy, Inc. representing at least 50% of the total voting power represented by Crosstex Energy, Inc.'s then outstanding voting securities.

If a change in control were to have occurred as of December 31, 2009, option's restricted stock and performance shares held by the named executive officers would have automatically vested and become payable or exercisable, and any vesting periods of restricted stock would have terminated, as follows:

- Barry E. Davis held 104,167 shares of restricted stock and 213,744 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control;

- William W. Davis held 91,667 shares of restricted stock and 103,035 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control;

- Joe A. Davis held 91,667 shares of restricted stock and 87,634 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Michael J. Garberding held 34,079 shares of restricted stock would have become fully vested, payable and/or exercisable as a result of such change in control; and
- Stan Golemon held 48,167 shares of restricted stock would have become fully vested, payable and/or exercisable as a result of such change in control; and

Role of Executive Officers in Executive Compensation.

The board of directors of Crosstex Energy GP LLC, upon recommendation of the Committee, determines the compensation payable to each of the named executive officers. None of the named executive officers serves as a member of the Committee. Barry E. Davis, the Chief Executive Officer, reviews his recommendations regarding the compensation of his leadership team with the Committee, including specific recommendations for each element of compensation for the named executive officers. Barry E. Davis does not make any recommendations regarding his personal compensation.

Tax and Accounting Considerations.

The equity compensation grant policies of the Crosstex entities have been impacted by the implementation of FASB ACS 718, which we adopted effective January 1, 2006. Under this accounting pronouncement, we are required to value unvested unit options granted prior to our adoption of FASB ACS 718 under the fair value method and expense those amounts in the income statement over the stock option's remaining vesting period. As a result, the Crosstex entities currently intend to discontinue grants of unit option and stock option awards and instead grant restricted unit and restricted stock awards to the named executive officers and other employees. The Crosstex entities have structured the compensation program to comply with Internal Revenue Code Section 409A. If an executive is entitled to nonqualified deferred compensation benefits that are subject to Section 409A, and such benefits do not comply with Section 409A, then the benefits are taxable in the first year they are not subject to a substantial risk of forfeiture. In such case, the service provider is subject to regular federal income tax, interest and an additional federal income tax of 20% of the benefit includible in income. None of the named executive officers or other employees had non-performance based compensation paid in excess of the $1.0 million tax deduction limit contained in Internal Revenue Code Section 162(m).

Summary Compensation Table

The following table sets forth certain compensation information for our named executive officers.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Stock Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Barry E. Davis	2009	435,000	435,000	1,117,712	—	—	—	45,327(3)	2,033,039
President and Chief Executive Officer	2008	435,000	78,000	1,154,104	—	—	—	356,580	2,023,684
	2007	400,000	400,000	1,111,409	—	—	—	213,210	2,124,619
William W. Davis	2009	315,000	315,000	983,587	—	—	—	37,120(4)	1,650,707
Executive Vice President and	2008	315,000	147,000	557,137	—	—	—	220,452	1,239,589
Chief Financial Officer	2007	290,000	226,000	534,691	—	—	—	227,411	1,278,102
Joe A. Davis	2009	285,000	385,000(8)	983,587	—	—	—	32,370(5)	1,685,957
Executive Vice President and	2008	285,000	43,000	504,085	—	—	—	234,324	1,066,409
General Counsel	2007	265,000	226,000	366,422	—	—	—	137,440	994,862
Michael J. Garberding	2009	198,000	117,000	312,962	—	—	—	18,274(6)	646,236
Senior Vice President									
Stan Golemon	2009	220,000	132,000	447,087	—	—	—	18,820(7)	817,907
Senior Vice President									

(1) Bonuses include all payments made under the Annual Cash Bonus Plan and Key Employee Retention Plan. See discussion on page 72.

(2) The amounts shown represent the grant date fair value of awards computed in accordance with FASB ACS 718. See Note 11 to our audited financial statements included in Item 8 herein for the assumptions made in our valuation of such awards. Values for awards subject to performance conditions are computed based upon the probable outcome of the performance condition as of the grant date of the award. With respect to the performance units and shares received during 2007 and 2008 (see discussion on page 74), the table below shows (i) minimum and maximum possible payouts based upon the grant date fair value of the underlying securities, and (ii) the currently expected payouts at the closing prices as of December 31, 2009 of $8.60 for Crosstex Energy, L.P.'s common units and $6.05 for Crosstex Energy, Inc.'s common shares:

Name	Grant Year	Payout Date	Maximum Payout (at grant date fair value)	Minimum Payout (at grant date fair value)	Expected Payout (at 12/31/09 market value)
Barry E. Davis	2007	3/1/2010	$ 2,222,819	$ 333,412	$ 75,518
	2008	3/1/2011	$ 11,541,116	$ 1,154,105	$ 266,551
William W. Davis	2007	3/1/2010	$ 1,069,382	$ 160,352	$ 36,333
	2008	3/1/2011	$ 5,571,538	$ 557,138	$ 128,676
Joe A. Davis	2007	3/1/2010	$ 732,844	$ 109,914	$ 24,905
	2008	3/1/2011	$ 4,259,968	$ 504,085	$ 116,422

(3) Amount of all other compensation for Mr. Barry Davis includes professional organization and social club dues, a matching 401(k) contribution of $16,500, distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $19,571 in 2009 and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $6,975 in 2009.

(4) Amount of all other compensation for Mr. William Davis includes professional organization and social club dues, a matching 401(k) contribution of $22,000, distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $9,424 in 2009 and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $3,360 in 2009.

(5) Amount of all other compensation for Mr. Joe Davis includes professional organization and social club dues, a matching 401(k) contribution of $16,500, distributions on restricted units and performance units of Crosstex Energy, L.P. in the amount of $9,900 in 2009 and dividends on restricted stock and performance shares of Crosstex Energy, Inc. in the amount of $3,634 in 2009.

(6) Amount of all other compensation for Mr. Michael Garberding includes a matching 401(k) contribution of $16,500, distributions on restricted units of Crosstex Energy, L.P. in the amount of $1,332 in 2009 and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $442 in 2009.

(7) Amount of all other compensation for Mr. Stan Golemon includes a matching 401(k) contribution of $16,500, distributions on restricted units of Crosstex Energy, L.P. in the amount of $1,735 in 2009 and dividends on restricted stock of Crosstex Energy, Inc. in the amount of $585 in 2009.

(8) In addition to bonuses received under the Annual Cash Bonus Plan and Key Employee Retention Plan, Mr. Joe A. Davis received a discretionary bonus in the amount of $100,000.

Grants of Plan-Based Awards for Fiscal Year 2009 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2009, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plans.

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

Name	Grant Date	Number of Units (#) (1)	Grant Date Fair Value of Unit Awards ($)
Barry E. Davis	12/15/09	104,167	647,919
William W. Davis	12/15/09	91,667	570,169
Joe A. Davis	12/15/09	91,667	570,169
Michael J. Garberding	12/15/09	29,167	181,419
Stan Golemon	12/15/09	41,667	259,169

(1) These grants include Distribution Equivalent Rights (DERs) that provide for distributions on restricted units if made on unrestricted common units during the restriction period unless otherwise forfeited.

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

Name	Grant Date	Number of Shares (#)(1)	Grant Date Fair Value of Stock Awards ($)
Barry E. Davis	12/15/09	104,167	469,793
William W. Davis	12/15/09	91,667	413,418
Joe A. Davis	12/15/09	91,667	413,418
Michael J. Garberding	12/15/09	29,167	131,543
Stan Golemon	12/15/09	41,667	187,918

(1) These grants include the right to receive dividends on restricted shares if made on unrestricted common shares during the restricted period unless otherwise forfeited.

Outstanding Equity Awards at Fiscal Year-End Table for Fiscal Year 2009

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2009, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plans.

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

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(3)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(2)
Barry E. Davis	—	—	—	—	—	104,167(1)	895,836	4,824(4) 18,596(5)	41,486 159,926
William W. Davis	—	—	—	—	—	91,667(1)	788,336	2,331(4) 8,977(5)	20,047 77,202
Joe A. Davis	—	—	—	—	—	91,667(1)	788,336	1,598(4) 8,122(5)	13,743 69,849
Michael J. Garberding	—	—	—	—	—	29,167(1) 5,327(6)	250,836 45,812	—	—
Stan Golemon	—	—	—	—	—	41,667(1) 6,940(6)	358,336 59,684	—	—

(1) Restricted units vest in three equal installments on January 1, 2011, 2012 and 2013.

(2) The closing price for the common units was $8.60 as of December 31, 2009.

(3) Performance units reported at the threshold (minimum) number of units. See discussion on page 74.

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

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

(6) Restricted units vest on April 1, 2011.

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

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(3)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(2)
Barry E. Davis	—	—	—	—	—	104,167(1)	630,210	5,625(4)	34,031
								17,624(5)	106,625
William W. Davis	—	—	—	—	—	91,667(1)	554,585	2,692(4)	16,287
								8,508(5)	51,473
Joe A. Davis	—	—	—	—	—	91,667(1)	554,585	1,845(4)	11,162
								7,698(5)	46,573
Michael J. Garberding	—	—	—	—	—	29,167(1)	176,460	—	—
						4,912(6)	29,718		
Stan Golemon	—	—	—	—	—	41,667(1)	252,085	—	—
						6,500(6)	39,325		

(1) Restricted shares vest in three equal installments on January 1, 2011, 2012, and 2013.

(2) The closing price for the common stock was $6.05 as of December 31, 2009.

(3) Performance shares reported at the threshold (minimum) number of shares. See discussion on page 75.

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

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

(6) Restricted shares vest on April 1, 2011.

Option Exercises and Units and Shares Vested Table for Fiscal Year 2009

The following table provides information related to the exercise of options and vesting of restricted units and restricted shares during fiscal year ended 2009.

OPTION EXERCISES AND UNITS AND SHARES VESTED

	Crosstex Energy, L.P. Unit Awards		Crosstex Energy, Inc. Share Awards	
Name	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
Barry E. Davis	16,667	72,835	38,154	135,901
William W. Davis	10,145	44,334	36,594	123,367
Joe A. Davis	7,199	22,389	8,565	35,716
Michael J. Garberding	—	—	—	—
Stan Golemon	—	—	—	—

Compensation of Directors for Fiscal Year 2009

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards(1) ($)	All Other Compensation(2) ($)	Total ($)
Rhys J. Best	165,500	100,001	1,055	266,556
Leldon E. Echols	67,875	37,500	277	105,652
Bryan H. Lawrence	—	—	—	—
Sheldon B. Lubar	58,126	37,500	777	96,403
Cecil E. Martin	71,156	37,500	777	109,433
Kyle D. Vann	84,000	75,000	1,055	160,055

(1) Messrs. Best, Echols, Lubar, Martin and Vann were granted awards of restricted units of Crosstex Energy, L.P. on August 13, 2009 with a fair market value of $3.75 per unit and that will vest on May 7, 2010 in the following amounts, respectively: 26,667, 10,000, 10,000, 10,000, and 20,000. The amounts shown represent the grant date fair value of awards computed in accordance with FASB ACS 718. See Note 11 to our audited financial statements included in Item 8 herein for the assumptions made in our valuation of such awards. At December 31, 2009, Messrs. Best, Echols, Lubar, Martin and Vann held aggregate outstanding restricted unit awards, in the following amounts, respectively: 26,667, 10,000, 10,000, 10,000, and 20,000. Mr. Lawrence held no outstanding restricted unit awards at December 31, 2009.

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

Each director of Crosstex Energy GP, LLC who is not an employee of Crosstex Energy GP, LLC (other than Mr. Lawrence and Mr. Scott) is paid an annual retainer fee of $50,000, except for Mr. Best who, as Chairman, is paid an annual retainer fee of $137,000. Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting, but are paid $1,500 for each additional meeting that they attend. Also, an attendance fee of $1,500 is paid to each director for each committee meeting that is attended, other than the Audit Committee, which pays a fee of $3,000 per meeting. The respective Chairs of each committee receive the following annual fees: Audit - $7,500, Compensation — $7,500, Governance — $5,000, and Conflicts — $2,500. Directors are also reimbursed for related out-of-pocket expenses. Barry E. Davis, as an executive officer of Crosstex Energy GP, LLC, is otherwise compensated for his services and therefore receives no separate compensation for his service as a director. For directors that serve on both the boards of Crosstex Energy GP, LLC and Crosstex Energy, Inc., the above listed fees are generally allocated 75% to us and 25% to Crosstex Energy, Inc., except in the case for service on the Audit Committee, where the Chair is paid a separate fee for each entity and meeting fees are split 50% to each entity. The Governance Committee annually reviews and makes recommendations to the Board of Directors regarding the compensation of the directors. Mr. Lawrence received no compensation in 2009. See related party transactions for a discussion of compensation for Mr. Scott.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended 2009, the Committee was composed of Cecil E. Martin and Rhys J. Best. No member of the Committee during fiscal 2009 was a current or former officer or employee of Crosstex Energy GP, LLC or had any relationship requiring disclosure by us under Item 404 of Regulation S-K as adopted by the SEC. None of Crosstex Energy GP, LLC's executive officers served on the board of directors or the compensation committee of any other entity, for which any officers of such other entity served either on Crosstex Energy GP, LLC's Board of Directors or the Committee.

The Compensation Committee of Crosstex Energy GP, LLC held six meetings during fiscal year 2009. Each member attended 100% of the meetings.

Board Leadership Structure and Risk Oversight

The Board of Directors of Crosstex Energy GP, LLC has no policy that requires that the positions of the Chairman of the Board and the Chief Executive Officer be separate or that they be held by the same individual. The Board believes that this determination should be based on circumstances existing from time to time, including the current business environment and any specific challenges facing the business and the composition, skills, and experience of the board and its members. At this time, positions of Chairman of the Board and the Chief Executive Officer of Crosstex Energy GP, LLC are not held by the same individual. Rhys J. Best serves as the Chairman of the Board and Barry E. Davis serves as the President and Chief Executive Officer. The Board of Directors believes this is the most appropriate structure for the Partnership at this time because it makes the best use of Mr. Best's skills and experience, including his prior service as the Chief Executive Officer of a large public company, while enhancing Mr. Davis' ability to lead decisively and communicate our message and strategy clearly and consistently to our unitholders, employees and customers.

The Board of Directors is responsible for risk oversight. Management has implemented internal processes to identify and evaluate the risks inherent in the Company's business, and to assess the mitigation of those risks. The Audit Committee has reviewed the risk assessments with management and provided reports to the Board regarding the internal risk assessment processes, the risks identified, and the mitigation strategies planned or in place to address the risks in the business. The Board and the Audit Committee each provide insight into the issues, based on the experience of their members, and provide constructive challenges to management's assumptions and assertions.

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

Crosstex Energy, L.P. Ownership

The following table shows the beneficial ownership of units of Crosstex Energy, L.P. as of February 16, 2010, held by:

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

Percentages reflected in the table are based upon a total of 49,710,468 common units and 14,705,882 Series A Convertible Preferred units as of February 16, 2010.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Series A Convertible Preferred Units Beneficially Owned	Percentage of Preferred Units Beneficially Owned	Total Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Crosstex Energy, Inc.	16,414,830	33.02%	0	*	16,414,830	25.48%
GSO Crosstex Holdings LLC(2)	0	*	14,705,882	100.00%	14,705,882	22.83%
Kayne Anderson Capital Advisors, L.P.(3)	5,571,410	11.21%	0	*	5,571,410	8.65%
Barry E. Davis(4)	253,059	*	0	*	253,059	*
William W. Davis(4)	31,306	*	0	*	31,306	*
Joe A. Davis(4)	24,440	*	0	*	24,440	*
Michael J. Garberding	0	*	0	*	0	*
Stan Golemon	1,618	*	0	*	1,618	*
Rhys J. Best	44,218	*	0	*	44,218	*
Leldon E. Echols (4)	1,109	*	0	*	1,109	*
Bryan H. Lawrence(4)	0	*	0	*	0	*
Sheldon B. Lubar(4)(5)	358,048	*	0	*	358,048	*
Cecil E. Martin (4)	20,119	*	0	*	20,119	*
D. Dwight Scott	0	*	0	*	0	*
Kyle D. Vann	50,228	*	0	*	50,228	*
All directors and executive officers as a group (12 persons)	784,145	1.58%	0	*	784,145	1.22%

* Less than 1%

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for GSO Crosstex Holdings LLC, which is 280 Park Avenue, 11th Floor, New York, NY 10017, Kayne Anderson Capital Advisors, L.P., which is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067; and Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022.

(2) As reported on Schedule 13D filed with the SEC in a joint filing with Blackstone / GSO Capital Solutions Fund LP, Blackstone / GSO Capital Solutions Associates LLC, Bennett J. Goodman, J. Albert Smith III, Douglas I. Ostrover, GSO Holdings I LLC, Blackstone Holdings I L.P., Blackstone Holdings I/II GP Inc., The Blackstone Group L.P., Blackstone Group Management L.L.C., and Stephen A. Schwarzman.

(3) As reported on Schedule 13G filed with the SEC in a joint filing with Richard A. Kayne. Such persons report shared voting and dispositive power with respect to the units.

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

(5) Sheldon B. Lubar is a general partner of Lubar Nominees, which holds an ownership interest in Crosstex Energy, Inc. (as indicated in the following table). Mr. Lubar is also a director of the manager of Lubar Equity Fund, LLC, which holds an ownership interest in Crosstex Energy, Inc. (as indicated in the following table) and owns 323,107 Units of Crosstex Energy, L.P.

Crosstex Energy, Inc. Ownership

The following table shows the beneficial ownership of Crosstex Energy, Inc. as of February 16, 2010, held by:

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

Percentages reflected in the table below are based on a total of 46,589,022 shares of common stock outstanding as of February 16, 2010.

Name of Beneficial Owner(1)	Shares of Common Stock	Percent
Brave Warrior Capital, Inc.(2)	4,526,099	9.71%
BlackRock, Inc. (3)	2,535,606	5.44%
Lubar Nominees(4)	1,991,877	4.28%
Lubar Equity Fund, LLC(4)	535,471	1.15%
Barry E. Davis	1,593,370	3.42%
William W. Davis	171,511	*
Joe A. Davis	38,901	*
Michael J. Garberding	0	*
Stan Golemon	0	*
James C. Crain(5)	9,669	*
Leldon E. Echols	1,085	*
Bryan H. Lawrence	1,720,267	3.69%
Sheldon B. Lubar(4)	16,085	*
Cecil E. Martin	1,085	*
Robert F. Murchison(6)	231,521	*
All directors and executive officers as group (11 persons)	6,310,842	13.55%

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for BlackRock, Inc. which is 40 East 52nd Street, New York, New York 10022; Brave Warrior Capital, Inc. which is 12 East 49th Street, New York, New York 10017; and Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022.

(2) As reported on schedule 13 G/A filed with the SEC. Bryan R. Lawrence is a principal of Brave Warrior Capital, Inc. and he is the son of our director Bryan H. Lawrence.

(3) As reported on Schedule 13G filed with the SEC. Such person reports that it has shared voting and dispositive power with respect to the shares.

(4) Sheldon B. Lubar is a general partner of Lubar Nominees and director of the manager of Lubar Equity Fund, LLC, and may be deemed to beneficially own the shares held by these entities.

(5) 1,000 of these shares are held by the James C. Crain Trust.

(6) 169,462 shares are held by Murchison Capital Partners, L.P. Mr. Murchison is the President of the Murchison Management Corp., which serves as the general partner of Murchison Capital Partners, L.P.

Beneficial Ownership of General Partner Interest

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

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a)	Weighted-Average Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plan (Excluding Securities Reflected in Column(a)) (c)
Equity Compensation Plans Approved By Security Holders(1)	3,074,742(2)	$ 6.43(3)	1,401,982
Equity Compensation Plans Not Approved By Security Holders	N/A	N/A	N/A

(1) Our Amended and Restated Long-Term Incentive Plan was approved by our unitholders in May 2009 for the benefit of our officers, employees and directors. See Item 11, "Executive Compensation — Compensation Discussion and Analysis." The plan, as amended, provides for issuance of a total of 5,600,000 common unit options and restricted units.

(2) The number of securities includes (i) 2,043,557 restricted units that have been granted under our long-term incentive plan that have not vested, and (ii) 148,165 performance units which could result in grants of restricted units in the future.

(3) The exercise prices for outstanding options under the plan as of December 31, 2009 range from $3.11 to $37.31 per unit.

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

Our General Partner

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

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

Relationship with Crosstex Energy, Inc.

General. CEI owns 16,414,830 common units, representing approximately 25% limited partnership interest in us as of January 31, 2010. Our general partner owns a 2% general partner interest in us and the incentive distribution rights. Our general partner's ability, as general partner, to manage and operate Crosstex Energy, L.P. and Crosstex Energy, Inc.'s ownership in us effectively gives our general partner the ability to veto some of our actions and to control our management. Crosstex Energy, Inc. pays us for administrative and compensation costs that we incur on its behalf. During 2009, this fee was approximately $0.07 million per month.

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

Related Party Transactions

Reimbursement of Costs by CEI. CEI paid us $0.8 million, $0.7 million and $0.6 million during the years ended December 31, 2009, 2008, and 2007, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI.

GSO Crosstex Holdings LLC. GSO Crosstex Holdings LLC owns 14,705,882 Series A Convertible Preferred Units representing limited partner interests, representing approximately 22% limited partnership interest in us as of January 31, 2010. In connection with the sale of the Series A Convertible Preferred Units to GSO Crosstex Holdings LLC, we entered into a Board Representation Agreement by and among our general partner, Crosstex Energy GP, LLC, CEI and GSO Crosstex Holdings LLC. Pursuant to the Board Representation Agreement, each of the Crosstex entities agreed to take all actions necessary or advisable to cause one director serving on the Board to be designated by GSO Crosstex Holdings LLC, in its sole discretion. Such designation right will terminate upon the earliest to occur of (i) GSO Crosstex Holdings LLC and its affiliates holding a number of Series A preferred units and common units issued on conversion of the Series A preferred units that is less than twenty-five percent (25%) of the number of Series A preferred units initially issued to GSO Crosstex Holdings LLC, (ii) such time as the sum of (A) the number of common units into which the Series A preferred units collectively held by GSO Crosstex Holdings LLC and its affiliates are convertible and (B) the number of the common units issuable upon conversion of the Series A preferred units which are then collectively held by GSO Crosstex Holdings LLC and its affiliates represent less than ten percent (10%) of the common units then outstanding and (iii) GSO Crosstex Holdings LLC ceasing to be an affiliate of The Blackstone Group L.P. GSO Crosstex Holdings LLC has selected D. Dwight Scott to serve as a director. GSO Crosstex Holdings LLC (or its affiliates) requires that any compensation due to Mr. Scott be paid directly to GSO Crosstex Holdings LLC (or its designee). As a result, we will pay GSO Crosstex Holdings LLC (or its designee) all cash compensation (and the cash value at the date of grant of any equity compensation) otherwise payable to Mr. Scott for his service as a director in accordance with our director compensation policies in place from time to time.

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

Director Independence

See "Item 10. Directors, Executive Officers and Corporate Governance" for information regarding director independence.

Item 14. *Principal Accounting Fees and Services*

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for each of the fiscal years ended December 31, 2009 and December 31, 2008, review of our internal control procedures for the fiscal year ended December 31, 2009 and December 31, 2008, and the reviews of the financial statements included in our Quarterly Reports on Forms 10-Q or services that are normally provided by KPMG in connection with statutory or regulatory filings or engagements for each of those fiscal years were $1.2 million. These amounts also included fees associated with comfort letters and consents related to debt and equity offerings.

Audit-Related Fees

KPMG did not perform any assurance and related services related to the performance of the audit or review of our financial statements for the fiscal years ended December 31, 2009 and December 31, 2008 that were not included in the audit fees listed above.

Tax Fees

We did not incur any fees by KPMG for tax compliance, tax advice and tax planning for the years ended December 31, 2009 and December 31, 2008.

All Other Fees

KPMG did not render services to us, other than those services covered in the section captioned "Audit Fees" for the fiscal years ended December 31, 2009 and December 31, 2008.

Audit Committee Approval of Audit and Non-Audit Services

All audit and non-audit services and any services that exceed the annual limits set forth in our annual engagement letter for audit services must be pre-approved by the Audit Committee. In 2010, the Audit Committee has not pre-approved the use of KPMG for any non-audit related services. The Chairman of the Audit Committee is authorized by the Audit Committee to pre-approve additional KPMG audit and non-audit services between Audit Committee meetings; provided that the additional services do not affect KPMG's independence under applicable Securities and Exchange Commission rules and any such pre-approval is reported to the Audit Committee at its next meeting.

PART IV

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

(a) Financial Statements and Schedules

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

(2) See Schedule II — Valuation and Qualifying Accounts on Page F-42.

(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
2.1**	—	Partnership Interest Purchase and Sale Agreement, dated as of June 9, 2009, among Crosstex Energy Services, L.P., Crosstex Energy Services GP, LLC, Crosstex CCNG Gathering, Ltd., Crosstex CCNG Transmission Ltd., Crosstex Gulf Coast Transmission Ltd., Crosstex Mississippi Pipeline, L.P., Crosstex Mississippi Gathering, L.P., Crosstex Mississippi Industrial Gas Sales, L.P., Crosstex Alabama Gathering System, L.P., Crosstex Midstream Services, L.P., Javelina Marketing Company Ltd., Javelina NGL Pipeline Ltd. and Southcross Energy LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated June 9, 2009, filed with the Commission on June 11, 2009, file No. 000-50067).
2.2**	—	Partnership Interest Purchase and Sale Agreement, dated as of August 28, 2009, among Crosstex Energy Services, L.P., Crosstex Energy Services GP, LLC, Crosstex Treating Services, L.P. and KM Treating GP LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated August 28, 2009, filed with the Commission on September 3, 2009, file No. 000-50067).
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007, file No. 000-50067).
3.3	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007, file No. 000-50067).
3.4	—	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 27, 2008, filed with the Commission on March 28, 2008, file No. 000-50067).
3.5	—	Amendment No. 3 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of January 19, 2010 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
3.6	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004, file No. 000-50067).
3.8	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).

Number	Description
3.9	— Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference to Exhibit 3.6 to our Registration Statement on Form S-1, file No. 333-97779).
3.10	— Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.11	— Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
3.12	— Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of January 19, 2010 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
4.1	— Specimen Unit Certificate for Common Units (incorporated by reference to Exhibit 4.7 to Amendment No. 1 to our Registration Statement on Form S-3, file No. 333-128282).
4.2	— Registration Rights Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007, file No. 000-50067).
4.3	— Registration Rights Agreement, dated as of January 19, 2010, by and among Crosstex Energy, L.P. and GSO Crosstex Holdings LLC (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
4.4	— Indenture, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
4.5	— Registration Rights Agreement, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
10.1†	— 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, file No. 000-50536).
10.2†	— Crosstex Energy GP, LLC Amended and Restated Long-Term Incentive Plan, dated March 17, 2009 (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, file No. 000-50067).
10.3†	— Crosstex Energy, Inc. 2009 Long-Term Incentive Plan, effective March 17, 2009 (incorporated by reference to Exhibit 10.3 to Crosstex Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, file No. 000-50536).
10.4	— Omnibus Agreement, dated December 17, 2002, among Crosstex Energy, L.P. and certain other parties (incorporated by reference to Exhibit 10.5 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.5†	— Form of Employment Agreement (incorporated by reference to Exhibit 10.6 to our Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.6†*	— Form of Severance Agreement.

Number		Description
10.7	—	Senior Subordinated Series D Unit Purchase Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007, file No. 000-50067).
10.8†	—	Form of Performance Unit Agreement (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007, file No. 000-50067).
10.9†*	—	Form of Restricted Unit Agreement.
10.10†	—	Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.9 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2009, file No. 000-50536).
10.11†	—	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, file No. 000-50536).
10.12	—	Common Unit Purchase Agreement, dated as of April 8, 2008, by and among Crosstex Energy, L.P. and each of the Purchasers set forth Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated April 9, 2008, file No. 000-50067).
10.13	—	Form of Indemnity Agreement (incorporated by reference to 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).
10.14	—	Board Representation Agreement, dated as of January 19, 2010, by and among Crosstex Energy GP, LLC, Crosstex Energy GP, L.P., Crosstex Energy, L.P., Crosstex Energy, Inc. and GSO Crosstex Holdings LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated January 19, 2010, filed with the Commission on January 22, 2010, file No. 000-50067).
10.15	—	Purchase Agreement, dated as of February 3, 2010, by and among Crosstex Energy, L.P., Crosstex Energy Finance Corporation, the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 3, 2010, filed with the Commission on February 5, 2010, file No. 000-50067).
10.16	—	Amended and Restated Credit Agreement, dated as of February 10, 2010, by and among Crosstex Energy, L.P., Bank of America, N.A., as Administrative Agent and L/C Issuer thereunder, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 10, 2010, filed with the Commission on February 16, 2010, file No. 000-50067).
12.1*	—	Ratio of Earnings to Fixed Charges.
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.

** In accordance with the instructions to Item 601(b)(2) of Regulation S-K, the exhibits and schedules to Exhibits 2.1 and 2.2 are not filed herewith. The agreements identify such exhibits and schedules, including the general nature of their content. We undertake to provide such exhibits and schedules to the Commission upon request.

† As required by Item 15(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 26th day of February 2010.

CROSSTEX ENERGY, L.P.

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

By: Crosstex Energy GP, LLC, its general partner

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

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

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2010
/s/ RHYS J. BEST Rhys J. Best	Chairman of the Board	February 26, 2010
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 26, 2010
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Director	February 26, 2010
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	February 26, 2010
/s/ CECIL E. MARTIN Cecil E. Martin	Director	February 26, 2010
/s/ D. DWIGHT SCOTT D. Dwight Scott	Director	February 26, 2010
/s/ KYLE D. VANN Kyle D. Vann	Director	February 26, 2010
/s/ WILLIAM W. DAVIS William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2010

INDEX TO FINANCIAL STATEMENTS

Crosstex Energy, L.P. Financial Statements:

Financial Statement Schedule:

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

In connection with the preparation of the Partnership's annual consolidated financial statements, management has undertaken an assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Partnership's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2009, the Partnership's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

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

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We have audited the accompanying consolidated balance sheets of Crosstex Energy, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2009 and 2008 and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedule. These consolidated financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Crosstex Energy, L.P. and subsidiaries as of December 31, 2009 and 2008 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2009, 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 February 26, 2010, expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 26, 2010

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

We have audited Crosstex Energy, L.P.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Partnership as of December 31, 2009 and 2008, and the related consolidated statements of operations, changes in Partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 26, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 26, 2010

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets

	December 31, 2009	December 31, 2008
	(In thousands except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 779	$ 1,636
Accounts receivable:		
Trade, net of allowance for bad debts of $410 and $3,655, respectively	27,434	49,185
Accrued revenues	180,221	292,668
Imbalances	6,020	3,893
Other	1,084	7,728
Fair value of derivative assets	9,112	27,166
Natural gas and natural gas liquids, prepaid expenses and other	14,692	9,645
Total current assets	239,342	391,921
Property and equipment:		
Transmission assets	382,965	474,771
Gathering systems	605,981	614,572
Gas plants	457,139	577,250
Other property and equipment	78,988	70,618
Construction in process	12,693	86,462
Total property and equipment	1,537,766	1,823,673
Accumulated depreciation	(258,706)	(296,393)
Total property and equipment, net	1,279,060	1,527,280
Fair value of derivative assets	5,665	4,628
Intangible assets, net of accumulated amortization of $115,813 and $89,231, respectively	534,897	578,096
Goodwill	—	19,673
Other assets, net	10,217	11,668
Total assets	$ 2,069,181	$ 2,533,266
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 5,214	$ 21,514
Accounts payable	17,977	23,879
Accrued gas purchases	150,816	270,229
Accrued imbalances payable	5,702	7,100
Fair value of derivative liabilities	30,337	28,506
Current portion of long-term debt	28,602	9,412
Other current liabilities	51,014	64,191
Total current liabilities	289,662	424,831
Long-term debt	845,100	1,254,294
Other long-term liabilities	20,797	24,708
Deferred tax liability	8,234	8,727
Fair value of derivative liabilities	12,106	22,775
Commitments and contingencies	—	—
Partners' equity:		
Common unitholders (49,163,293 and 44,908,522 units issued and outstanding at December 31, 2009 and 2008, respectively)	873,858	674,564
Senior subordinated series D unitholders (3,875,340 units issued and outstanding at December 31, 2008)	—	99,942
General partner interest (2% interest with 1,003,333 and 995,556 equivalent units outstanding at December 31, 2009 and 2008)	18,860	16,805
Non-controlling interest	3,234	3,510
Accumulated other comprehensive income (loss)	(2,670)	3,110
Total partners' equity	893,282	797,931
Total liabilities and partners' equity	$ 2,069,181	$ 2,533,266

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Years Ended December 31,		
	2009	2008	2007
	(In thousands except per unit data)		
Revenues:			
Midstream	$ 1,453,346	$ 3,072,646	$ 2,380,224
Gas and NGL marketing activities	5,744	3,365	4,105
Total revenues	1,459,090	3,076,011	2,384,329
Operating costs and expenses:			
Purchased gas	1,147,868	2,768,225	2,124,503
Operating expenses	110,394	125,754	91,202
General and administrative	59,854	68,864	59,493
Gain on derivatives	(2,994)	(8,619)	(4,147)
Gain on sale of property	(666)	(947)	(1,024)
Impairments	2,894	29,373	—
Depreciation and amortization	119,088	107,521	83,315
Total operating costs and expenses	1,436,438	3,090,171	2,353,342
Operating income (loss)	22,652	(14,160)	30,987
Other income (expense):			
Interest expense, net of interest income	(95,078)	(74,971)	(48,059)
Loss on extinguishment of debt	(4,669)	—	—
Other income	1,400	27,770	538
Total other income (expense)	(98,347)	(47,201)	(47,521)
Loss from continuing operations before non-controlling interest and income taxes	(75,695)	(61,361)	(16,534)
Income tax provision	(1,790)	(2,369)	(760)
Loss from continuing operations before discontinued operations	(77,485)	(63,730)	(17,294)
Discontinued operations:			
Income (loss) from discontinued operations	(1,796)	25,007	31,343
Gain on sale of discontinued operations	183,747	49,805	—
Discontinued operations (net of tax)	181,951	74,812	31,343
Net income	$ 104,466	$ 11,082	$ 14,049
Less: Net income attributable to the non-controlling interest	60	311	160
Net income attributable to Crosstex Energy, L.P.	$ 104,406	$ 10,771	$ 13,889
General partner interest in net income (loss)	$ (819)	$ 26,415	$ 19,252
Limited partners' interest in net income (loss)	$ 105,225	$ (15,644)	$ (5,363)
Net income (loss) per limited partners' unit: Basic common unit	$ 1.44	$ (3.19)	$ (0.20)
Diluted common unit	$ 1.40	$ (3.19)	$ (0.20)
Basic and diluted senior subordinated series C units (see Note 9(e))	$ —	$ 9.44	$ —
Basic and diluted senior subordinated series D units (see Note 9(e))	$ 8.85	$ —	$ —

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Years ended December 31, 2009, 2008 and 2007

	Common Units $	Common Units Units	Subordinated Units $	Subordinated Units Units	Sr. Subordinated C Units $	Sr. Subordinated C Units Units	Sr. Subordinated D Units $	Sr. Subordinated D Units Units	General Partner Interest $	General Partner Interest Units	Accumulated Other Comprehensive Income (loss)	Non-Controlling Interest	Total
Balance, December 31, 2006	$ 330,492	19,616	$ (6,402)	7,001	$ 359,319	12,830	$ —	—	$ 20,472	805	$ 7,996	$ 3,655	$ 715,532
Issuance of common units	57,550	1,800	—	—	—	—	—	—	—	—	—	—	57,550
Proceeds from exercise of unit options	1,598	90	—	—	—	—	—	—	—	—	—	—	1,598
Issuance of Sr. subordinated series D units	—	—	—	—	—	—	99,942	3,875	—	—	—	—	99,942
Conversion of subordinated units	(3,872)	2,333	3,872	(2,333)	—	—	—	—	—	—	—	—	—
Conversion of restricted units for common units, net of units withheld for taxes	(329)	29	—	—	—	—	—	—	—	—	—	—	(329)
Capital contributions	—	—	—	—	—	—	—	—	4,014	118	—	—	4,014
Stock-based compensation	5,478	—	1,228	—	—	—	—	—	5,578	—	—	—	12,284
Distributions	(49,810)	—	(11,950)	—	—	—	—	—	(24,765)	—	—	—	(86,525)
Net income (loss)	(3,936)	—	(1,427)	—	—	—	—	—	19,252	—	—	160	14,049
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	(3,706)	—	(3,706)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	(25,768)	—	(25,768)
Balance December 31, 2007	337,171	23,868	(14,679)	4,668	359,319	12,830	99,942	3,875	24,551	923	(21,478)	3,815	788,641
Issuance of common units	99,888	3,333	—	—	—	—	—	—	—	—	—	—	99,888
Proceeds from exercise of unit options	850	57	—	—	—	—	—	—	—	—	—	—	850
Conversion of subordinated units	341,816	17,498	17,503	(4,668)	(359,319)	(12,830)	—	—	—	—	—	—	—
Conversion of restricted units for common units, net of units withheld for taxes	(1,536)	153	—	—	—	—	—	—	—	—	—	—	(1,536)
Capital contributions	—	—	—	—	—	—	—	—	2,193	73	—	109	2,302
Stock-based compensation	6,337	—	109	—	—	—	—	—	4,797	—	—	—	11,243
Distributions	(94,404)	—	(2,847)	—	—	—	—	—	(41,151)	—	—	—	(138,402)
Net income (loss)	(15,558)	—	(86)	—	—	—	—	—	26,415	—	—	311	11,082
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	20,840	—	20,840
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	3,748	—	3,748
Distribution to non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(725)	(725)
Balance December 31, 2008	674,564	44,909	—	—	—	—	99,942	3,875	16,805	996	3,110	3,510	797,931
Proceeds from exercise of unit options	67	2	—	—	—	—	—	—	—	—	—	—	67
Conversion of subordinated units	99,942	4,069	—	—	—	—	(99,942)	(3,875)	—	—	—	—	—
Conversion of restricted units for common units, net of units withheld for taxes	(232)	183	—	—	—	—	—	—	—	—	—	—	(232)
Capital contributions	—	—	—	—	—	—	—	—	21	7	—	—	21
Stock-based compensation	5,660	—	—	—	—	—	—	—	3,082	—	—	—	8,742
Distributions	(11,368)	—	—	—	—	—	—	—	(229)	—	—	—	(11,597)
Net income (loss)	105,225	—	—	—	—	—	—	—	(819)	—	—	60	104,466
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	(2,412)	—	(2,412)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	(3,368)	—	(3,368)
Distribution to non-controlling interest	—	—	—	—	—	—	—	—	—	—	—	(336)	(336)
Balance December 31, 2009	$ 873,858	49,163	$ —	—	$ —	—	$ —	—	$ 18,860	1,003	$ (2,670)	$ 3,234	$ 893,282

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Years Ended December 31,		
	2009	2008	2007
	(In thousands)		
Net income	$ 104,466	$ 11,082	$ 14,049
Hedging gains or losses reclassified to earnings	(2,412)	20,840	(3,706)
Adjustment in fair value of derivatives	(3,368)	3,748	(25,768)
Comprehensive income (loss)	98,686	35,670	(15,425)
Comprehensive income attributable to non-controlling interest	60	311	160
Comprehensive income (loss) attributable to Crosstex Energy, L.P.	$ 98,626	$ 35,359	$ (15,585)

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 104,466	$ 11,082	$ 14,049
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	129,737	132,899	108,880
Non-cash stock-based compensation	8,742	11,243	12,284
Gain on sale of property	(184,412)	(51,325)	(1,667)
Impairments	2,894	30,436	—
Deferred tax (benefit) expense	(468)	172	253
Non-cash derivatives loss	2,184	23,510	2,418
Non-cash loss on debt extinguishment	4,669	—	—
Interest paid-in-kind	10,134	—	—
Amortization of debt issue costs	11,812	2,854	2,639
Changes in assets and liabilities, net of acquisition effects:			
Accounts receivable, accrued revenue and other	128,083	156,248	(121,300)
Natural gas and natural gas liquids, prepaid expenses and other	(5,288)	5,176	(5,566)
Accounts payable, accrued gas purchases and other accrued liabilities	(131,563)	(148,545)	101,993
Fair value of derivatives	(12)	—	835
Net cash provided by operating activities	80,978	173,750	114,818
Cash flows from investing activities:			
Additions to property and equipment	(101,370)	(275,590)	(414,452)
Insurance recoveries on property and equipment	12,458	—	—
Acquisitions and asset purchases	(35,142)	—	—
Proceeds from sales of property	503,928	88,780	3,070
Net cash provided (used) in investing activities	379,874	(186,810)	(411,382)
Cash flows from financing activities:			
Proceeds from borrowings	632,807	1,743,580	1,189,500
Payments on borrowings	(1,050,389)	(1,702,992)	(953,512)
Proceeds from capital lease obligations	1,695	28,010	3,553
Payments on capital lease obligations	(2,414)	(4,101)	—
Decrease in drafts payable	(16,300)	(7,417)	(19,017)
Debt refinancing costs	(15,031)	(4,903)	(892)
Conversion of restricted units, net of units withheld for taxes	(232)	(1,536)	(329)
Distributions to non-controlling interest	(336)	(725)	—
Distribution to partners	(11,597)	(138,402)	(86,525)
Proceeds from exercise of unit options	67	850	1,598
Net proceeds from common unit offerings	—	99,888	57,550
Issuance of subordinated units	—	—	99,942
Contribution from partners	21	2,193	4,014
Contributions from non-controlling interest	—	109	—
Net cash provided (used) by financing activities	(461,709)	14,554	295,882
Net increase (decrease) in cash and cash equivalents	(857)	1,494	(682)
Cash and cash equivalents, beginning of period	1,636	142	824
Cash and cash equivalents, end of period	$ 779	$ 1,636	$ 142
Cash paid for interest	$ 85,466	$ 76,291	$ 79,648
Cash paid for income taxes	$ 1,376	$ 1,371	$ 38

See accompanying notes to consolidated financial statements.

(1) Organization and Summary of Significant Agreements

(a) Description of Business

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

(b) Partnership Ownership

Crosstex Energy GP, L.P., the general partner of the Partnership, is an indirect wholly-owned subsidiary of Crosstex Energy, Inc. (CEI). As of December 31, 2009, CEI owns 16,414,830 common units in the Partnership through its wholly-owned subsidiaries. As of December 31, 2009, CEI owned 33.0% of the limited partner interests in the Partnership.

After the Partnership's January 2010 issuance of Series A Convertible Preferred Units as discussed in Note 18, the common units owned by CEI represent 25.0% 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 Partnership and its wholly-owned subsidiaries. The Partnership proportionately consolidates its undivided 59.27% interest in a gas processing plant. In accordance with ASC 810-10-05-8, the Partnership consolidates its joint venture interest in Crosstex DC Gathering, J.V. (CDC) as discussed more fully in Note 5. The consolidated operations are hereafter referred to herein collectively as the "Partnership." All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for the prior years to conform to the current presentation.

(2) Significant Accounting Policies

(a) Management's Use of Estimates

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

(b) Cash and Cash Equivalents

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

(c) Natural Gas and Natural Gas Liquids Inventory

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

(d) Property, Plant, and Equipment

Property, plant and equipment consist of intrastate gas transmission systems, gas gathering systems, industrial supply pipelines, NGL pipelines, natural gas processing plants and NGL fractionation plants. Gas required to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Other property and equipment is primarily comprised of idle gas plants and equipment, computer software and equipment, furniture, fixtures, leasehold improvements and office equipment. Property, plant and equipment are recorded at cost. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest costs are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use. Interest costs totaling $1.1 million, $2.7 million and $4.8 million, were capitalized for the years ended December 31, 2009, 2008 and 2007, respectively.

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

	Useful Lives
Transmission assets	20-30 years
Gathering systems	15-20 years
Gas processing plants	20 years
Other property and equipment	3-15 years

Depreciation expense of $82.4 million, $76.1 million and $57.0 million was recorded for the years ended December 31, 2009, 2008 and 2007, respectively. During the fourth quarter of 2009, we reviewed the estimated useful lives and salvage values of our assets in light of the capital improvements made to our assets over the past years. As a result of this review, we extended the depreciable lives on some of our transmission assets, gathering systems and gas processing plants by five years. This change in estimated depreciable lives is being applied prospectively and will result in lower depreciation expense of approximately $9.3 million annually in future periods.

FASB ASC 360-10-05-4 requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If an impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset.

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

The Partnership recorded impairments to long-lived assets of $2.9 million and $24.6 million during the years ending December 31, 2009 and 2008, respectively. See Note 3(c) for further details on the long-lived assets impaired.

(e) Goodwill and Intangibles

Goodwill created in the formation of the Partnership of $4.9 million net book value associated with the Midstream assets was impaired during the year ending December 31, 2008 leaving goodwill on the Partnership books as of December 31, 2008 of $19.7 million. This goodwill related to the acquisition of Treating assets and was eliminated in the disposition of all Treating assets during 2009.

Intangible assets consist of customer relationships and the value of the dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems. Intangible assets associated with customer relationships 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 non-dedicated acreage attributable to pipeline, gathering and processing systems are being amortized using the units of throughput method of amortization. The weighted average amortization period for intangible assets is 18.0 years. Amortization expense for intangibles was approximately $36.6 million, $31.4 million and $26.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

2010	$ 40,646
2011	42,642
2012	45,303
2013	46,731
2014	46,701
Thereafter	312,874
Total	$ 534,897

(f) Other Assets

Unamortized debt issuance costs totaling $10.2 million and $11.7 million as of December 31, 2009 and 2008, respectively, are included in other assets, net. Debt issuance costs are amortized into interest expense using the effective-interest method over the term of the debt for the senior secured notes. Debt issuance costs are amortized using the straight-line method over the term of the debt for the bank credit facility because borrowings under the bank credit facility cannot be forecasted for an effective-interest computation.

(g) Gas Imbalance Accounting

Quantities of natural gas and NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as receivables or payables using weighted average prices at the time of the imbalance. These imbalances are typically settled with deliveries of natural gas or NGLs. The Partnership had imbalance payables of $5.7 million and $7.1 million at December 31, 2009 and 2008, respectively, which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $6.0 million and $3.9 million at December 31, 2009 and 2008, which are carried at the lower of cost or market value.

(h) Asset Retirement Obligations

FASB ASC 410-20-25-16 was issued March 2005, which became effective at December 31, 2005. FASB ASC 410-20-25-16 clarifies that the term "conditional asset retirement obligation" as used in FASB ASC 410-20, 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, FASB ASC 410-20-25-16 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. FASB ASC 410-20-25-16 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB ASC 410-20. The Partnership did not provide any asset retirement obligations as of December 31, 2009 or 2008 because it does not have sufficient information as set forth in FASB ASC 410-20-25-16 to reasonably estimate such obligations and the Partnership has no current intention of discontinuing use of any significant assets.

(i) Revenue Recognition

The Partnership recognizes revenue for sales or services at the time the natural gas, or NGLs are delivered or at the time the service is performed. The Partnership generally accrues one month of sales and the related gas purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates. The Partnership's purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the statements of operations in accordance with FASB ASC 605-45-45-1. Except for fee based arrangements and the Partnership's energy trading activities related to its "off-system" gas marketing operations discussed in Note 2(k), the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, schedules the transportation and assumes credit risk.

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

(j) Derivatives

The Partnership uses derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. FASB ASC 815 requires that all derivatives be recorded on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The asset or liability related to the derivative instruments is recorded on the balance sheet in fair value of derivative assets or liabilities.

Realized and unrealized gains and losses on commodity related 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. Realized and unrealized gains and losses on interest rate derivatives that are not designated as hedges are included in interest expense 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) Gas and NGL Marketing Activities

The Partnership conducts "off-system" gas marketing operations as a service to producers on systems that the Partnership does not own. The Partnership refers to these activities as its Gas and NGL marketing activities. In some cases, the Partnership earns an agency fee from the producer for arranging the marketing of the producer's natural gas or NGLs. In other cases, the Partnership purchases the natural gas or NGLs from the producer and enters into a sales contract with another party to sell the natural gas or NGLs. The revenue and cost of sales for Gas and NGL marketing activities are shown net in the consolidated statement of operations.

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

Net margins earned on settled contracts from the Partnership's Gas and NGL marketing activities included in Gas and NGL marketing activities in the consolidated statement of operations were $5.7 million, $3.4 million and $4.1 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Gas and NGL marketing contract volumes that were physically settled were as follows (in MMBtus):

	Years Ended December 31,		
	2009	2008	2007
Volumes purchased and sold	27,375,000	31,003,000	34,432,000

(l) Comprehensive Income (Loss)

Comprehensive income includes net income (loss) and other comprehensive income, which includes unrealized gains and losses on derivative financial instruments. Pursuant to FASB ASC 815, the Partnership records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

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

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

(n) Concentrations of Credit Risk

Financial instruments, which potentially subject the Partnership to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited since the Partnership's customers represent a broad and diverse group of energy marketers and end users. In addition, the Partnership continually monitors and reviews credit exposure to its marketing counter-parties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. The Partnership records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Partnership had a reserve for uncollectible receivables as of December 31, 2009, 2008 and 2007 of $0.4 million, $3.7 million and $1.0 million, respectively. The increase in the reserve during 2008 primarily relates to SemStream, L.P. (Semstream). The decrease in the reserve during 2009 primarily relates to the write-off of the Semstream reserve and related receivable. See Note 16(d) for a discussion of the bankruptcy filing of SemStream.

During 2009, 2008 and 2007 Dow Hydrocarbons accounted for 12.2%, 11.0% and 11.8%, respectively, of the consolidated revenue of the Partnership including discontinued operations. As the Partnership continues to grow and expand, the relationship between individual customer sales and consolidated total sales is expected to continue to change. While this customer represents a significant percentage of revenues, the loss of this customer would not have a material adverse impact on the Partnership's results of operations.

(o) Environmental Costs

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For the years ended December 31, 2009, 2008 and 2007, such expenditures were not significant.

(p) Option Plans

The Partnership recognizes compensation cost related to all stock-based awards, including stock options, in its consolidated financial statements in accordance with FASB ASC 718. The Partnership and CEI each have similar unit or share-based payment plans for employees, which are described below. Share-based compensation associated with the CEI share-based compensation plans awarded to officers and employees of the Partnership are recorded by the Partnership since CEI has no operating activities other than its interest in the Partnership. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Cost of share-based compensation charged to general and administrative expense	$ 7,075	$ 9,364	$ 10,442
Cost of share-based compensation charged to operating expense	1,667	1,879	1,842
Total amount charged to income	8,742	$ 11,243	$ 12,284

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

(q) Recent Accounting Pronouncements

As a result of the recent credit crisis, FASB ASC 820-10-35-15A was issued in October 2008 and clarifies the application of FASB ASC 820 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. FASB ASC 820-10-35-15A is effective upon issuance, for companies that have adopted FASB ASC 820. The Partnership has evaluated FASB ASC 820-10-35-15A and determined that this standard has no impact on its results of operations, cash flows or financial position for this reporting period.

FASB ASC 260-10-45-60 was issued June 2008 and requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB ASC 260. FASB ASC 260-10-45-60 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. The Partnership adopted FASB ASC 260-10-45-60 effective January 1, 2009 and adjusted all prior periods to conform to the requirements.

FASB ASC 805 and FASB ASC 810-10-65-1 were issued December 2007. FASB ASC 805 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 FASB ASC 805 all business combinations will be accounted for by applying the acquisition method. FASB ASC 805 is effective for periods beginning on or after December 15, 2008. FASB ASC 810-10-65-1 requires 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. FASB ASC 810-10-65-1 was adopted effective January 1, 2009 and comparative period information has been recast to classify non-controlling interests in equity, and attribute net income and other comprehensive income to non-controlling interests.

FASB ASC 105 was released July 1, 2009 and intended to improve financial reporting by identifying a consistent framework, or hierarchy, for selecting accounting principles to be used in preparing financial statements of non-governmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. SFAS No. 162 has been superseded by SFAS No. 168, "*The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*" (the Codification) released July 1, 2009. The Codification became the exclusive authoritative reference for non-governmental U.S. GAAP for use in financial statements issued for interim and annual periods ending after September 15, 2009, except for Securities and Exchange Commission (SEC) rules and interpretive releases, which are also authoritative GAAP for SEC registrants. The change establishes non-governmental U.S. GAAP into the authoritative Codification and guidance that is non-authoritative. The contents of the Codification carry the same level of authority, eliminating the four-level GAAP hierarchy previously set forth in Statement 162. The Codification supersedes all existing non-SEC accounting and reporting standards. All other non-grandfathered, non-SEC accounting literature not included in the Codification has become non-authoritative. The Partnership has revised all GAAP references to reflect the Codification for the year ended December 31, 2009.

FASB ASC 815-10-65-1 was issued March 2008 and 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 FASB ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. FASB ASC 815-10-65-1 is effective for fiscal years beginning after November 15, 2008. FASB ASC 815-10-65-1 was adopted effective January 1, 2009. Required disclosures were added to Note 13.

FASB ASC 260-10-55-102 was released in March 2008 and addresses the consensus reached by the Task Force that incentive distribution rights (IDRs) in a typical master limited partnership are participating securities under FASB ASC 260, but earnings in excess of the partnership's "available cash" should not be allocated to the IDR holders for purposes of calculating earnings-per-share using the two-class method when "available cash" represents a specified threshold that limits participation. The consensus only applies when payments to IDR holders are accounted for as equity distributions. The consensus is effective for fiscal years beginning after December 15, 2008 and applied retrospectively to all periods presented. Under the Partnership's partnership agreement, "available cash" is a specified threshold that limits participation for IDR holders. Therefore earnings in excess of the Partnership's available cash, if any, are not allocated to IDR holders.

In June 2009 FASB ASC 810-10-05-8 was issued. It requires reporting entities to evaluate former Qualifying Special Purpose Entities or QSPEs for consolidation, changes the approach to determining a variable interest entity's (VIE) primary beneficiary from a quantitative assessment to a qualitative assessment designed to identify a controlling financial interest, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. This statement requires additional year-end and interim disclosures for public and nonpublic companies that are similar to the disclosures required by FASB ASC 860-10-65-2. The statement is effective for fiscal years beginning after November 15, 2009 and for subsequent interim and annual reporting periods. The Partnership does not expect this statement to have a significant impact to its financial statements.

FASB ASC 855 was issued June 2009 and is effective for interim or annual financial periods ending after June 15, 2009 and addresses accounting and disclosure requirements related to subsequent events. The statement requires management to evaluate subsequent events through the date the financial statements are issued. Companies are required to disclose the date through which subsequent events have been evaluated. The Partnership has taken this statement into consideration in Note 18.

FASB ASC 825-10-65-1 requires publicly traded companies to disclose the fair value of financial instruments within the scope of FASB ASC 825 in interim financial statements, adding to the current requirement to make those disclosures in annual financial statements. FASB ASC 825-10-65-1 is effective for interim and annual periods ending after June 15, 2009. The Partnership has added the required footnote disclosure in interim financial statements.

(3) Discontinued Operations, Impairments and Dispositions

(a) Discontinued Operations

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

In November 2008, the Partnership disposed of its undivided 12.4% interest in the Seminole gas processing plant to a third party for $85.0 million and recognized a gain of $49.8 million. This asset was previously presented in the Partnership's Treating segment and its values are included in the Treating revenues and net income from discontinued operations presented in the years ended December 31, 2008 and 2007 in the table below.

The revenues, operating expenses, general and administrative expenses associated directly with the sold assets, depreciation and amortization expense, Treating inventory impairment of $1.0 million during 2009, allocated Texas margin tax and an allocated interest expense related to the operations of the sold assets have been segregated from continuing operations and reported as discontinued operations for all periods. Interest expense of $34.4 million, $29.2 million and $32.7 million for the years ended December 31, 2009, 2008 and 2007, respectively, was allocated to discontinued operations related to the debt repaid from the proceeds from the asset dispositions using average historical interest rates for each of the three years. The interest allocation for 2009 also included make-whole interest payments and the write-off of unamortized debt issue costs related to the debt repaid. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are revenues and income from discontinued operations (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Midstream revenues	$ 368,142	$ 1,766,101	$ 1,411,092
Treating revenues	$ 45,534	$ 73,492	$ 65,025
Income (loss) from discontinued operations, net of tax	$ (1,796)	$ 25,007	$ 31,343
Gain from sale of discontinued operations, net of tax	$ 183,747	$ 49,805	$ —

(b) Other Disposition

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

(c) Long-Lived Asset Impairments

Impairments of $2.9 million and $24.6 million were recorded in the year ended December 31, 2009 and 2008, respectively, related to long-lived assets. During 2009, impairments totaling $2.9 million were taken on the Bear Creek processing plant and the Vermillion treating plant to bring the fair value of the plants to a marketable value for these idle assets. The impairment expense during 2008 is:

- $17.8 million related to the Blue Water gas processing plant located in south Louisiana — The impairment on the Partnership's 59.27% interest in the Blue Water gas processing plant was recognized because the pipeline company which owns the offshore Blue Water system and supplies gas to the Partnership's Blue Water plant reversed the flow of the gas on its pipeline in early January 2009 thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system. As of January 2009, the Partnership has not found an alternative source of new gas for the Blue Water plant so the plant ceased operations from January 2009 until November 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 was not in operation.

- $4.1 million related to leasehold improvements — The Partnership had planned to relocate its corporate office during 2008 to a larger office facility. The Partnership had leased office space and was close to completing the renovation of this office space when the global economic decline began impacting its operations in October 2008. On December 31, 2008, the decision was made to cancel the new office lease and not relocate the corporate offices from its existing office location. The impairment relates to the leasehold improvements on the office space for the cancelled lease.

- $2.6 million related to the Arkoma gathering system — The impairment on the Arkoma gathering system was recognized because the Partnership sold this asset in February 2009 for approximately $10.7 million and the carrying amount of the asset exceeded the sale price by approximately $2.6 million.

(4) Goodwill

Goodwill on the Partnership books as of December 31, 2008 related solely to the Treating assets which were sold in October 2009. 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. As a result, the Partnership recognized an impairment loss of $4.9 million in the Midstream segment for the year ended December 31, 2008.

(5) Investment in Limited Partnerships and Note Receivable

The Partnership owns a majority interest in Crosstex Denton County Joint Venture (CDC) and consolidates its investment in CDC pursuant to FASB ASC 810-10-05-8. The Partnership manages the business affairs of CDC. The other joint venture partner (the CDC partner) is an unrelated third party who owns and operates a natural gas field located in Denton County, Texas.

In connection with the formation of CDC, the Partnership agreed to loan the CDC partner up to $1.5 million for its initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to the Partnership attributable to CDC partner's share of distributable cash flow to repay the loan. The balance remaining on the note of less than $0.1 million is included in current notes receivable as of December 31, 2009. The note was completely repaid in February 2010.

(6) Long-Term Debt

As of December 31, 2009 and 2008, long-term debt consisted of the following (in thousands):

	2009	2008
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2009 and 2008 were 6.75% and 3.9%, respectively	$ 529,614	$ 784,000
Senior secured notes (including PIK notes as defined below of $9.5 million), weighted average interest rates at December 31, 2009 and 2008 of 10.5% and 8.0%, respectively	326,034	479,706
Series B secured note assumed in the Eunice transaction, which bears interest at the rate of 9.5%	18,054	—
	873,702	1,263,706
Less current portion	(28,602)	(9,412)
Debt classified as long-term	$ 845,100	$ 1,254,294

Maturities. Maturities for the long-term debt as of December 31, 2009 are as follows (in thousands):

2010	28,602
2011	578,197
2012	93,000
2013	83,630
2014	67,380
Thereafter	22,893

The balance of the bank credit facility and senior secured notes was paid in full February 10, 2010 with the proceeds from the new credit facility and the senior unsecured notes.

Credit Facility. As of December 31, 2009, the Partnership had a bank credit facility with a borrowing capacity of $859.9 million that matures in June 2011. As of December 31, 2009, $683.0 million was outstanding under the bank credit facility, including $153.4 million of letters of credit, leaving approximately $176.9 million available for future borrowing.

New Credit Facility. In February 2010, the Partnership amended and restated its existing secured bank credit facility with a new syndicated secured bank credit facility (the "new credit facility"). The new credit facility has a borrowing capacity of $420.0 million and matures in February 2014. Net proceeds from the new credit facility along with net proceeds from the senior unsecured notes discussed under *"Senior Unsecured Notes"* below were used to, among other things, retire the Partnership's existing indebtedness.

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

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

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

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

Based on the forecasted leverage ratio for 2010, we expect the applicable margin for the interest rate and letter of credit fee to be at the higher end of these ranges. The new credit facility will not have a floor for the Base Rate or the Eurodollar Rate.

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

The maximum permitted leverage ratio will be as follows:

- 5.75 to 1.00 for the fiscal quarters ending March 31, 2010 and June 30, 2010;
- 5.50 to 1.00 for the fiscal quarter ending September 30, 2010;
- 5.25 to 1.00 for the fiscal quarter ending December 31, 2010;
- 5.00 to 1.00 for the fiscal quarter ending March 31, 2011;
- 4.75 to 1.00 for the fiscal quarter ending June 30, 2011; and
- 4.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

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

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

- 1.50 to 1.00 for the fiscal quarter ending March 31, 2010;
- 1.75 to 1.00 for the fiscal quarters ending June 30, 2010 through December 31, 2010;
- 2.00 to 1.00 for the fiscal quarter ending March 31, 2011;
- 2.25 to 1.00 for the fiscal quarter ending June 30, 2011; and
- 2.50 to 1.00 for the fiscal quarter ending September 30, 2011 and each fiscal quarter thereafter.

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

- grant or assume liens;
- make investments;
- incur or assume indebtedness;
- engage in mergers or acquisitions;
- sell, transfer, assign or convey assets,
- repurchase its equity, make distributions and certain other restricted payments;
- change the nature of our business;
- engage in transactions with affiliates.
- enter into certain burdensome agreements;
- make certain amendments to the omnibus agreement or its subsidiaries' organizational documents;
- prepay the senior unsecured notes and certain other indebtedness; and
- enter into certain hedging contracts.

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

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

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

- certain ERISA events involving the Partnership or any of its material subsidiaries, in excess of a threshold amount;
- bankruptcy or other insolvency events involving the Partnership or any of its material subsidiaries; and
- a change in control (as defined in the new credit facility).

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

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

The Partnership will be subject to interest rate risk on its new credit facility and may enter into interest rate swaps to reduce this risk.

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

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
June 2003	$ 1,607	9.45%
July 2003	1,000	9.38%
June 2004	50,629	9.46%
November 2005	57,380	8.73%
March 2006	40,504	8.82%
July 2006	165,390	9.46%
Total Outstanding	316,510	
PIK Notes Payable (1)	9,524	
Balance as of December 31, 2009 (2)	$ 326,034	

(1) The senior secured notes began accruing additional interest of 1.25% per annum in February 2009 (the "PIK notes") in the form of an increase in the principal amounts unless our leverage ratio is less than 4.25 to 1.00 as of the end of any fiscal quarter.

(2) The balance of senior secured notes was paid in full on February 10, 2010.

Series B Secured Note. On October 20, 2009, the Partnership acquired Eunice natural gas liquids processing plant and fractionation facility which includes $18.1 million in series B secured note. This note bears an interest rate of 9.5%. Payments including interest of $12.2 million and $7.4 million are due in 2010 and 2011, respectively.

Senior Unsecured Notes. On February 10, 2010, the Partnership issued $725.0 million in aggregate principal amount of 8.875% senior unsecured notes (the "notes") due on February 15, 2018 at an issue price of 97.907% to yield 9.25% to maturity. Net proceeds from the sale of the notes of $689.7 million (net of transaction costs and original issue discount), together with borrowings under its new credit facility discussed above, were used to repay in full amounts outstanding under its existing bank credit facility and senior secured notes and to pay related fees, costs and expenses, including the settlement of interest rate swaps associated with its existing credit facility. The notes are unsecured and unconditionally guaranteed on a senior basis by certain of our direct and indirect subsidiaries, including all of the Partnership's current subsidiaries other than Crosstex LIG, LLC and Crosstex Tuscaloosa, LLC, our Louisiana regulated entities, and Crosstex DC Gathering, J.V. Interest payments will be paid semi-annually in arrears starting on August 15, 2010.

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

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

If the notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services, many of these covenants will terminate.

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

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

Prior to February 15, 2014, the Partnership may redeem the notes, in whole or in part, at a "make-whole" redemption price. On or after February 15, 2014, the Partnership may redeem all or a part of the notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on February 15, 2014, 102.219% for the twelve-month period beginning February 15, 2015 and 100.00% for the twelve-month period beginning on February 15, 2016 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the notes.

Each of the following will be an event of default under the indenture:

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

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

The senior unsecured notes are jointly and severally guaranteed by each of the Partnership's current material subsidiaries (the "Guarantors"), with the exception of our regulated Louisiana subsidiaries (which may only guarantee up to $500.0 million of the Partnership's debt), CDC (our joint venture in Denton County, Texas not 100% owned by the Partnership) and Crosstex Energy Finance Corporation (a wholly owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Partnership's indebtedness, including the senior unsecured notes). Guarantors may not sell or otherwise dispose of all or substantially all of its properties or assets to, or consolidate with or merge into another company if such a sale would cause a default under the terms of the senior unsecured notes. Since certain wholly owned subsidiaries do not guarantee the senior unsecured notes, the condensed consolidating financial statements of the guarantors and non-guarantors as of and for the years ended December 31, 2009 and 2008 are disclosed below in accordance with Rule 3-10 of Regulation S-X.

Condensed Consolidating Balance Sheets
December 31, 2009

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
ASSETS				
Total current assets	$ 226,583	$ 12,759	$ —	$ 239,342
Property, plant and equipment, net	1,045,991	233,069	—	1,279,060
Total other assets	550,776	3	—	550,779
Total assets	$ 1,823,350	$ 245,831	$ —	$ 2,069,181
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 283,539	$ 6,123	$ —	$ 289,662
Long-term debt	845,100	—	—	845,100
Other long-term liabilities	41,137	—	—	41,137
Partners' capital	653,574	239,708	—	893,282
Total Liabilities & Partners' Capital	$ 1,823,350	$ 245,831	$ —	$ 2,069,181

December 31, 2008

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
ASSETS				
Total current assets	$ 379,532	$ 12,389	$	$ 391,921
Property, plant and equipment, net	1,303,034	224,246	—	1,527,280
Total other assets	614,062	3	—	614,065
Total assets	$ 2,296,628	$ 236,638	$ —	$ 2,533,266
LIABILITIES & PARTNERS' CAPITAL				
Total current liabilities	$ 412,259	$ 12,572	$ —	$ 424,831
Long-term debt	1,254,294	—	—	1,254,294
Other long-term liabilities	56,182	28	—	56,210
Partners' capital	573,893	224,038	—	797,931
Total liabilities & partners' capital	$ 2,296,628	$ 236,638	$ —	$ 2,533,266

Condensed Consolidating Statements of Operations
For the Year Ended December 31, 2009

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 1,417,393	$ 75,048	$ (33,351)	$ 1,459,090
Total operating costs and expenses	(1,437,623)	(32,166)	33,351	(1,436,438)
Operating income (loss)	(20,230)	42,882	—	22,652
Interest expense, net	(95,078)	—	—	(95,078)
Other income (loss)	(3,269)	—	—	(3,269)
Income from continuing operations before income taxes and non-controlling interest	(118,577)	42,882	—	(75,695)
Income tax provision	(1,770)	(20)	—	(1,790)
Income from discontinued operations	181,951	—	—	181,951
Net income attributable to non-controlling interest	(60)	—	—	(60)
Net income attributable to Crosstex Energy, L.P.	$ 61,544	$ 42,862	$ —	$ 104,406

For the Year Ended December 31, 2008

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Total revenues	$ 3,060,086	$ 61,879	$ (45,954)	$ 3,076,011
Total operating costs and expenses	(3,084,248)	(51,877)	45,954	(3,090,171)
Operating income (loss)	(24,162)	10,002	—	(14,160)
Interest expense, net	(74,971)	—	—	(74,971)
Other income and deductions, net	27,770	—	—	27,770
Income from continuing operations before income taxes and non-controlling interest	(71,363)	10,002	—	(61,361)
Income tax provision	(2,333)	(36)	—	(2,369)
Income from discontinued operations	74,812	—	—	74,812
Net income attributable to non-controlling interest	(311)	—	—	(311)
Net income attributable to Crosstex Energy, L.P.	$ 805	$ 9,966	$ —	$ 10,771

Condensed Consolidating Statements of Cash Flow
For the Year Ended December 31, 2009

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by operating activities	$ 31,194	$ 49,784	$ —	$ 80,978
Net cash flows (used in) provided by investing activities	$ 402,464	$ (22,590)	$ —	$ 379,874
Net cash flows (used in) provided by financing activities	$ (434,515)	$ (27,194)	$ —	$ (461,709)

For the Year Ended December 31, 2008

	Guarantors	Non Guarantors	Elimination	Consolidated
		(in thousands)		
Net cash flows provided by operating activities	$ 154,185	$ 19,565	$ —	$ 173,750
Net cash flows used in investing activities	$ (166,704)	$ (20,106)	$ —	$ (186,810)
Net cash flows provided by financing activities	$ 14,013	$ 541	$ —	$ 14,554

(7) Other Long-Term Liabilities

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

	Years Ended December 31,	
	2009	2008
Compressor equipment	$ 27,192	$ 28,890
Less: Accumulated amortization	(3,655)	(1,523)
Net assets under capital lease	$ 23,537	$ 27,367

The following are the minimum lease payments to be made in each of the following years indicated for the capital lease in effect as of December 31, 2009 (in thousands):

Fiscal Year	
2010 through 2014	$ 15,200
Thereafter	12,746
Less: Interest	(4,147)
Net minimum lease payments under capital lease	23,799
Less: Current portion of net minimum lease payments	(3,002)
Long-term portion of net minimum lease payments	$ 20,797

(8) Income Taxes

The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The net tax basis in the Partnership's assets and liabilities is less than the reported amounts on the financial statements by approximately $439.3 million as of December 31, 2009. Effective January 1, 2007, the Partnership is subject to the margin tax enacted by the state of Texas on May 1, 2006.

The LIG entities the Partnership formed to acquire the stock of LIG Pipeline Company and its subsidiaries, are treated as taxable corporations for income tax purposes. The entity structure was formed to effect the matching of the tax cost to the Partnership of a step-up in the basis of the assets to fair market value with the recognition of benefits of the step-up by the Partnership. A deferred tax liability of $8.2 million was recorded at the acquisition date. The deferred tax liability represents future taxes payable on the difference between the fair value and tax basis of the assets acquired. The Partnership, through ownership of the LIG entities, generated a net operating loss of $4.8 million during 2005 as a result of a tax loss on a property sale of which $0.9 million was carried back to 2004, $1.9 million was utilized in 2006 and substantially all of the remaining $2.0 million was utilized in 2007.

The Partnership provides for income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis that will reverse in future periods (in thousands).

	2009	2008	2007
Current tax provision (benefit)	$ 2,258	$ 2,197	$ 507
Deferred tax provision	(468)	172	253
Income tax provision on continuing operations	1,790	2,369	760
Income tax provision on discontinued operations (all current)	1,136	396	204
Tax provision	$ 2,926	$ 2,765	$ 964

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

	2009	2008	2007
Federal income tax on taxable corporation at statutory rate (35%)	$ 200	$ 197	$ 206
State income taxes, net	2,726	2,568	758
Income tax provision	$ 2,926	$ 2,765	$ 964

The principal component of the Partnership's net deferred tax liability is as follows (in thousands):

	Years Ended December 31, 2009	2008
Deferred income tax assets:		
Net operating loss carryforward — current	$ 1	$ 41
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets-current	$ (501)	$ (501)
Property, plant, equipment and intangible assets-long-term	(8,234)	(8,727)
	$ (8,735)	$ (9,228)
Net deferred tax liability	$ (8,734)	$ (9,187)

A net current deferred tax liability of $0.5 million is included in other current liabilities.

The Partnership adopted the provisions of FASB ASC 740-10-25-16 on January 1, 2007. A reconciliation of the beginning and ending amount of the unrecognized tax benefits is as follows (in thousands):

Balance as of December 31, 2007	$ —
Increases related to prior year tax positions	904
Increases related to current year tax positions	717
Balance as of December 31, 2008	$ 1,621
Increases related to prior year tax positions	385
Increases related to current year tax positions	1,118
Balance as of December 31, 2009	$ 3,124

Unrecognized tax benefits of $3.1 million, if recognized, would affect the effective tax rate. We do not expect the uncertain tax position to be resolved in 2010.

Per company policy, $0.2 million of penalties and interest related to prior year tax positions was recorded to income tax expense in 2009. 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, 2009, tax years 2006 through 2009 remain subject to examination by the Internal Revenue Service and tax years 2005 through 2009 remain subject to examination by various state taxing authorities.

(9) Partners' Capital

(a) Issuance of Common Units

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

(b) Conversion of Subordinated and Senior Subordinated Series C Units

The subordination period for the Partnership's subordinated units ended and the remaining 4,668,000 subordinated units converted into common units representing limited partner interests of the Partnership effective February 16, 2008.

On June 29, 2006, the Partnership issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests of the Partnership in a private equity offering for net proceeds of approximately $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represented a discount of 25% to the market value of common units on such date. CEI purchased 6,414,830 of the senior subordinated series C units. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $9.0 million in connection with this issuance to maintain its 2% general partner interest. The senior subordinated series C units converted into common units representing limited partner interests of the Partnership February 16, 2008. The senior subordinated series C units were not entitled to distributions of available cash from the Partnership until conversion. See Note 9(e) below for a discussion of the impact on earnings per unit resulting from the conversion of the senior subordinated series C units.

(c) Senior Subordinated Series D Units

On March 23, 2007, the Partnership issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests of the Partnership in a private offering. These senior subordinated series D units converted into common units representing limited partner interests of the Partnership on March 23, 2009. Since the Partnership did not make distribution of available cash from operating surplus, as defined in the partnership agreement, of at least $0.62 per unit on each outstanding common unit for the quarter ending December 31, 2008, each senior subordinated series D unit converted into 1.05 common units for a total issuance of 4,069,106 common units.

(d) Cash Distributions

Unless restricted by the terms of our credit facility, the Partnership must make distributions of 100.0% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter commencing with the quarter ended on March 31, 2003. Distributions will generally be made 98.0% to the common and subordinated unitholders and 2.0% to the general partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved.

Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13.0% of amounts we distribute in excess of $0.25 per unit, 23.0% of the amounts we distribute in excess of $0.3125 per unit and 48.0% of amounts we distribute in excess of $0.375 per unit. No incentive distributions were earned by the general partner for the year ended December 31, 2009. Incentive distributions totaling $30.8 million and $24.8 million were earned by our general partner for the years ended December 31, 2008 and 2007, respectively. The Partnership paid annual per common unit distributions of $0.25, $2.36 and $2.28 in the years ended December 31, 2009, 2008 and 2007, respectively.

The Partnership's ability to make distributions was restricted during 2009 by covenants associated with the long term debt.

(e) Earnings per unit and anti-dilutive computations

The Partnership's common units and subordinated units participate in earnings and distributions in the same manner for all historical periods and are therefore presented as a single class of common units for earnings per unit computations. The various series of senior subordinated units are also considered common securities, but because they do not participate in earnings or cash distributions during the subordination period are presented as separate classes of common equity. Each of the series of senior subordinated units were issued at a discount to the market price of the common units they are convertible into at the end of the subordination period. These discounts represent beneficial conversion features (BCFs) under FASB ASC 470-20-25-4. Under FASB ASC 470-20-25-4 and related accounting guidance, a BCF represents a non-cash distribution that is treated in the same way as a cash distribution for earnings per unit computations. Since the conversion of all the series of senior subordinated units into common units are contingent (as described with the terms of such units) until the end of the subordination periods for each series of units, the BCF associated with each series of senior subordinated units is not reflected in earnings per unit until the end of such subordination periods when the criteria for conversion are met. Following is a summary of the BCFs attributable to the senior subordinated units outstanding during 2007, 2008 and 2009 (in thousands):

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

FASB ASC 260-10-45-61A was issued in May 2008 with an effective date for fiscal years beginning after December 15, 2008 and interim periods within those years. This FASB ASC requires unvested share-based payments that entitle employees to receive non-forfeitable distributions to also be considered participating securities, as defined in FASB ASC 260-10-20. The Partnership was impacted by this FASB ASC and has calculated earnings attributable to unvested restricted units and adjusted earnings per unit calculations for the comparative periods to reflect implementation of this FASB ASC.

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

	Years Ended December 31,		
	2009	2008	2007
Limited partners' interest in net income (loss)	$ 105,225	$ (15,644)	$ (5,363)
Distributed earnings allocated to:			
Common units(1)	$ 11,234	$ 95,961	$ 60,851
Unvested restricted units	134	1,290	909
Senior subordinated series C units(2)	—	121,112	—
Senior subordinated series D units(2)	34,297	—	—
Total distributed earnings	$ 45,665	$ 218,363	$ 61,760
Undistributed earnings (loss) allocated to:			
Common units(3)	$ 58,220	$ (230,903)	$ (66,068)
Unvested restricted units (3)	1,340	(3,104)	(1,055)
Senior subordinated series C units	—	—	—
Senior subordinated series D units	—	—	—
Total undistributed earnings (loss)	$ 59,560	$ (234,007)	$ (67,123)
Net income (loss) allocated to:			
Common units	$ 69,454	$ (134,942)	$ (5,217)
Unvested restricted units	1,474	(1,814)	(146)
Senior subordinated series C units	—	121,112	—
Senior subordinated series D units	34,297	—	—
Total limited partners' interest in net income (loss)	$ 105,225	$ (15,644)	$ (5,363)
Limited Partner's interest in income from discontinued operations:			
Common units	$ 174,278	$ 72,420	$ 30,234
Unvested restricted units	4,034	896	483
Total income from discontinued operation (4)	$ 178,312	$ 73,316	$ 30,717
Basic and diluted net loss per unit from continuing operations:			
Basic and diluted common units	$ (2.18)	$ (4.90)	$ (1.33)
Senior subordinated series C units	$ —	$ 9.44	$ —
Senior subordinated series D units	$ 8.85	$ —	$ —
Basic and diluted net income from discontinued operations:			
Basic common units	$ 3.62	$ 1.71	$ 1.13
Diluted common units	$ 3.52	$ 1.71	$ 1.13
Senior subordinated series C and D units	$ —	$ —	$ —
Total basic and diluted net income (loss) per unit:			
Basic common units	$ 1.44	$ (3.19)	$ (0.20)
Diluted common units	$ 1.40	$ (3.19)	$ (0.20)
Senior subordinated series C units	$ —	$ 9.44	$ —
Senior subordinated series D units	$ 8.85	$ —	$ —

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

(2) Represents BCF recognized at end of subordination period for senior subordinated series C and D units.

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

(4) Represents 98.0% for the limited partners' interest in discontinued operations.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2009, 2008, and 2007 (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Basic and diluted earnings per unit:			
Weighted average limited partner common units outstanding	48,161	42,330	26,753
Diluted earnings per unit:			
Weighted average limited partner units outstanding	48,161	42,330	26,753
Dilutive effect of restricted units issued	433	—	—
Dilutive effect of senior subordinated units	871	—	—
Dilutive effect of exercise of options outstanding	2	—	—
Dilutive common units	49,467	42,330	26,753
Weighted average diluted senior subordinated series C units outstanding	—	12,830	—
Weighted average diluted senior subordinated series D units outstanding	3,875	—	—

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented. All common unit equivalents were antidilutive for the years ended December 31, 2008 and 2007 because the limited partners were allocated net losses in the periods.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note 9(d). As stated in the partnership agreement, the general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest the subordinated units and the common units. The net income allocated to the general partner is as follows (in thousands):

	Years Ended December 31,		
	2009	2008	2007
Income allocation for incentive distributions	$ —	$ 30,772	$ 24,802
Stock-based compensation attributable to CEI's stock options and restricted shares	(2,966)	(4,665)	(5,441)
2% general partner interest in net income (loss)	2,147	308	(109)
General partner share of net income	$ (819)	$ 26,415	$ 19,252

(10) Retirement Plans

The Partnership sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The plan allows for contributions to be made at each compensation calculation period based on the annual discretionary contribution rate. Contributions of $3.1 million, $3.4 million, and $1.6 million were made to the plan for the years ended December 31, 2009, 2008 and 2007, respectively.

(11) Employee Incentive Plans

(a) Long-Term Incentive Plan

The Partnership's managing general partner has a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 5,600,000 common unit options and restricted units. The plan is administered by the compensation committee of the managing general partner's board of directors. The units issued upon exercise or vesting are newly issued units.

(b) Restricted Units

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the restricted units will become exercisable upon a change of control of the Partnership, its general partner or its general partner's general partner.

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted in 2009, 2008 and 2007 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, 2009 is provided below:

Crosstex Energy, L.P. Restricted Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	544,067	$ 31.90
Granted	1,971,127	3.92
Vested*	(239,719)	17.34
Forfeited	(187,470)	10.64
Non-vested, end of period	2,088,005	$ 7.31
Aggregate intrinsic value, end of period (in thousands)	$ 17,957	

* Vested units include 56,067 units withheld for payroll taxes paid on behalf of employees.

The Partnership issued performance-based restricted units in 2007 and 2008 to executive officers. The minimum level of performance-based awards is included in restricted units outstanding and is included in the current share-based compensation cost calculations at December 31, 2009. The achievement of greater than the minimum performance targets in the current business environment is less than probable. All performance-based awards are subject to reevaluation and adjustment until the restricted units vest.

The Partnership awarded 803,632 restricted unit grants during the year ended December 31, 2009 to certain of the management team. Half of these units vest January 1, 2010. The remaining fifty percent of the units are performance-based awards that vest January 1, 2010 if the Partnership achieves certain performance metrics. As of December 31, 2009, the Partnership met the performance objectives stated in the grant with adjustments deemed necessary due to the disposition of assets in 2009. The performance-based units are shown in the balance of outstanding restricted units and included in the current share-based compensation calculations for the year ended December 31, 2009.

A summary of the restricted units aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2009, 2008 and 2007 are provided below (in thousands):

Crosstex Energy, L.P. Restricted Units:	Years Ended December 31, 2009	2008	2007
Aggregate intrinsic value of units vested	$ 1,023	$ 5,907	$ 1,342
Fair value of units vested	$ 4,158	$ 6,815	$ 888

As of December 31, 2009 there was $7.3 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.3 years.

(c) Unit Options

Unit options will have an exercise price that is not less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, its general partner or its general partner's general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior to estimate expected forfeiture rates. The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant. The Partnership used the simplified method to calculate the expected term.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant. The unit options granted in 2009, 2008 and 2007 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 2009, 2008 and 2007:

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options Granted:	**2009**	**2008**	**2007**
Weighted average distribution yield	0%	7.15%	5.75%
Weighted average expected volatility	76.2%	30.0%	32.0%
Weighted average risk free interest rate	2.34%	1.81%	4.39%
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	$ 2.89	$ 3.48	$ 6.73

A summary of the unit option activity for the years ended December 31, 2009, 2008 and 2007 is provided below:

	Years Ended December 31,					
	2009		2008		2007	
	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	1,304,194	$ 30.64	1,107,309	$ 29.65	926,156	$ 25.70
Granted(b)	636,122	4.46	402,185	31.58	347,599	37.29
Issued in Exchange	344,319	4.80	—	—	—	—
Rendered in Exchange	(1,032,403)	31.34	—	—	—	—
Exercised	(2,013)	4.08	(56,678)	14.16	(90,032)	18.20
Forfeited	(328,295)	27.51	(90,208)	31.29	(67,688)	29.84
Expired	(39,088)	30.30	(58,414)	32.93	(8,726)	31.60
Outstanding, end of period	882,836	$ 6.43	1,304,194	$ 30.64	1,107,309	$ 29.65
Options exercisable at end of period	159,929	$ 12.51	540,782	$ 29.12	281,973	$ 28.05
Weighted average contractual term (years) end of period:						
Options outstanding	8.7	—	7.4	—	7.6	—
Options exercisable	4.5	—	6.5	—	7.1	—
Aggregate intrinsic value end of period (in thousands):		—				
Options outstanding	$ 3,143	—	$ (a)	—	$ 4,681	—
Options exercisable	$ 336	—	$ (a)	—	$ 1,322	—

(a) Exercise price on all outstanding options exceed current market price.

(b) No options were granted with an exercise price less than or equal to market value at grant during 2009, 2008 and 2007.

In May 2009, the Partnership's unitholders approved an amendment to the Partnership's long-term incentive plan to allow an option exchange program. This option exchange program was offered to all eligible employees excluding executive officers and directors because options held by employees were "underwater," meaning the exercise price of the options were higher than the current market price of the common units. The terms of the offer included an exchange ratio of 3 old options for 1 replacement option with an exercise price of $4.80 per common unit (120% of the average closing sales price for five trading days prior to the date of grant) which will vest over 2 years (50% after year 1 and 50% after year 2). In June 2009, a total of 453 employees elected to exchange 1,032,403 old options for 344,319 replacement options pursuant to this option exchange program. There was no incremental compensation cost resulting from the modifications under this option exchange program.

A summary of the unit options intrinsic value exercised (market value in excess of exercise price at date of exercise) and fair value of units vested (value per Black-Scholes option pricing model at date of grant) during the years ended December 31, 2009, 2008 and 2007 are provided below (in thousands):

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options:	**2009**	**2008**	**2007**
Intrinsic value of units options exercised	$ 5	$ 746	$ 1,675
Fair value of units vested	$ 1,675	$ 279	$ 197

As of December 31, 2009, there was $1.5 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 2.2 years.

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

The Crosstex Energy, Inc. long-term incentive plans provides for the award of stock options and restricted stock (collectively, "Awards") for up to 7,190,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2010, approximately 2,230,800 shares remained available under the long-term incentive plans for future issuance to participants. A participant may not receive in any calendar year options relating to more than 250,000 shares of common stock. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Shares of common stock underlying. Awards that are forfeited, terminated or expire unexercised become immediately available for additional awards under the long-term incentive plan.

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. CEI's restricted stock granted in 2009, 2008 and 2007 generally cliff vest after three years of service. A summary of the restricted stock activity which includes officers and employees of the Partnership and directors of CEI for the year ended December 31, 2009, is provided below:

Crosstex Energy, Inc. Restricted Shares:	**Number of Shares**	**Weighted Average Grant-Date Fair Value**
Non-vested, beginning of period	604,313	$ 27.62
Granted	1,157,454	4.48
Vested*	(258,377)	16.96
Forfeited	(111,417)	16.30
Non-vested, end of period	1,391,973	$ 9.37
Aggregate intrinsic value, end of period (in thousands)	$ 8,421	

* Vested shares include 75,821 shares withheld for payroll taxes paid on behalf of employees.

The Company issued performance-based restricted shares in 2007 and 2008 to executive officers. The minimum level of performance-based awards is included in restricted shares outstanding and is included in the current share-based compensation cost calculations at December 31, 2009. The achievement of greater than the minimum performance targets in the current business environment is less than probable. All performance-based awards are subject to reevaluation and adjustment until the restricted shares vest.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value of shares vested (market value at date of grant) during the years ended December 31, 2009, 2008 and 2007 are provided below (in thousands):

Crosstex Energy, Inc. Restricted Shares:	Years Ended December 31, 2009	2008	2007
Aggregate intrinsic value of shares vested	$ 1,038	$ 13,493	$ 3,067
Fair value of shares vested	$ 4,382	$ 7,382	$ 1,275

Restricted shares in CEI totaling 244,915 and 205,983 were issued to directors, officers and employees of the Partnership with a weighted-average grant-date fair value of $32.41 and $26.13 per share in 2008 and 2007, respectively. As of December 31, 2009 there was $6.4 million of unrecognized compensation costs related to CEI restricted shares for directors, officers and employees. The cost is expected to be recognized over a weighted average period of 2.1 years.

CEI Stock Options

CEI stock options have not been granted since 2005. A summary of the stock option activity includes officers and employees of the Partnership and directors of CEI for the years ended December 31, 2009, 2008 and 2007 is provided below:

	Years Ended December 31, 2009		2008		2007	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Outstanding, beginning of period	67,500	$ 9.54	105,000	$ 8.45	120,000	$ 8.21
Exercised	—	—	(37,500)	6.50	(15,000)	6.50
Outstanding, end of period	67,500	$ 9.54	67,500	$ 9.54	105,000	$ 8.45
Options exercisable at end of period	67,500	$ 9.54	22,500	$ 11.05	37,500	$ 7.87

As of December 31, 2009 there were 30,000 exercisable outstanding CEI stock options at a weighted average exercise price of $13.33 attributable to the Partnership's officers and employees. On January 1, 2010 these outstanding stock options were forfeited.

A summary of the share options intrinsic value (market value in excess of exercise price at date of exercise) exercised and fair value of units vested (value per Black-Scholes option pricing model at date of grant) during the years ended December 31, 2009, 2008 and 2007 is provided below (in thousands):

Crosstex Energy, Inc. Stock Options:	Years Ended December 31, 2009	2008	2007
Intrinsic value of units options exercised	$ —	$ 1,089	$ 366
Fair value of units vested	$ 49	$ 38	$ 66

(12) Fair Value of Financial Instruments

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

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 779	$ 779	$ 1,636	$ 1,636
Trade accounts receivable and accrued revenues	207,655	207,655	341,853	341,853
Fair value of derivative assets	14,777	14,777	31,794	31,794
Accounts payable, drafts payable and accrued gas purchases	174,007	174,007	315,622	315,622
Long-term debt	873,702	872,340	1,263,706	1,158,351
Obligations under capital lease	23,799	22,399	27,896	27,269
Fair value of derivative liabilities	42,443	42,443	51,281	51,281

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

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $529.6 million and $784.0 million as of December 31, 2009 and 2008, 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, 2009, the Partnership also had borrowings totaling $326.0 million under senior secured notes with a weighted average interest rate of 10.5% and a series B secured note with a fixed rate of 9.5%. The fair value of these borrowings as of December 31, 2009 and 2008 were adjusted to reflect current market interest rate for such borrowings as of December 31, 2009 and 2008, 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 adjusted for credit risk of the Partnership and/or the counterparty as required under FASB ASC 820.

(13) Derivatives

Interest Rate Swaps

The Partnership is subject to interest rate risk on its credit facility and entered into interest rate swaps to reduce this risk. The Partnership originally entered into eight interest rate swaps to fix the three month Libor rate, prior to credit margin, at rates between 2.83% and 4.69% on notional amounts totaling $550.0 million with maturities as early as January 2009 and as late as October 31, 2011, as amended January 2008. In September 2008, the Partnership entered into four additional interest rate swaps to convert the floating rate portion of the original swaps on a notional amount of $450.0 million from three month LIBOR to one month LIBOR. These swaps were not designated as cash flow hedges and therefore 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.

The Partnership originally elected to designate all but one of the original eight interest rate swaps as cash flow hedges for FASB ASC 815 accounting treatment resulting in unrealized gains and losses booked in accumulated other comprehensive income. As a result of 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 date was to be reclassified to earnings over the remaining original terms of the swaps using the effective interest method. During 2009 the unrealized loss reclassified to earnings and included in other income (expense) as a part of interest expense, net, was $10.0 million which consisted of $6.7 million under the effective interest method and $3.3 million due to the Partnership's decision to reduce its credit facility in February 2010. The remaining unamortized balance in accumulated other comprehensive income is $0.6 million at December 31, 2009. This balance is associated with one swap of $50.0 million that as of December 31, 2009 the Partnership anticipated being in place to its original term.

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,		
	2009	2008	2007
Change in fair value of derivatives that do not qualify for hedge accounting	$ 797	$ (22,105)	$ (1,185)
Realized gains (losses) on derivatives	(19,044)	(4,608)	707
	$ (18,247)	$ (26,713)	$ (478)

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

	Years Ended December 31,	
	2009	2008
Fair value of derivative assets — current	$ —	$ 149
Fair value of derivative liabilities — current	(17,960)	(17,217)
Fair value of derivative liabilities — long-term	(6,768)	(18,391)
Net fair value of interest rate swaps	$ (24,728)	$ (35,459)

During the recapitalization of the Partnership in February 2010, all interest rates swaps held by the Partnership were settled and all remaining asset and liability balances on the books related to the interest rate swaps at December 31, 2009 have been removed and the impact of the transaction on net income has been included in other income (expense) in the first quarter of 2010.

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, processing margin swaps, and liquids 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. Liquids financial swaps are used to hedge price risk on percent of liquids (POL) contracts.

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

	Years Ended December 31,		
	2009	**2008**	**2007**
Change in fair value of derivatives that do not qualify for hedge accounting	$ 2,816	$ (246)	$ 1,197
Realized gains on derivatives	(6,139)	(13,352)	(7,918)
Ineffective portion of derivatives qualifying for hedge accounting	65	(72)	104
Net gains related to commodity swaps	(3,258)	(13,670)	(6,617)
Net gains included in income from discontinued operations	264	5,051	2,470
Gain on derivatives included in continuing operations	$ (2,994)	$ (8,619)	$ (4,147)

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

	Years Ended December 31,	
	2009	**2008**
Fair value of derivative assets — current, designated	$ 369	$ 13,714
Fair value of derivative assets — current, non-designated	8,743	13,303
Fair value of derivative assets — long term, non-designated	5,665	4,628
Fair value of derivative liabilities — current, designated	(2,536)	—
Fair value of derivative liabilities — current, non-designated	(9,841)	(11,289)
Fair value of derivative liabilities — long term, non-designated	(5,338)	(4,384)
Net fair value of derivatives	$ (2,938)	$ 15,972

Set forth below is the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at December 31, 2009 (all gas volumes are expressed in MMBtu's and liquids are expressed in gallons). The remaining terms of the contracts extend no later than December 2010 for derivatives, except for certain basis swaps that extend to March 2012. Changes in the fair value of the Partnership's mark to market derivatives are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings. The ineffective portion is recorded in earnings immediately.

December 31, 2009		
Transaction Type	**Volume**	**Fair Value**
	(In thousands)	
*Cash Flow Hedges:**		
Liquids swaps (short contracts)	(11,033)	$ (2,536)
Liquids swaps (long contracts)	1,247	369
Total swaps designated as cash flow hedges		$ (2,167)
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	155	$ 1
Physical offsets to swing swap transactions (short contracts)	(155)	—
Swing swaps (short contracts)	(682)	(3)
Physical offsets to swing swap transactions (long contracts)	682	—
Basis swaps (long contracts)	61,831	11,766
Physical offsets to basis swap transactions (short contracts)	(3,194)	18,553
Basis swaps (short contracts)	(47,938)	(8,626)
Physical offsets to basis swap transactions (long contracts)	3,194	(18,582)
Third-party on-system financial swaps (long contracts)	72	(184)
Third-party on-system financial swaps (short contracts)	(74)	(41)
Processing margin hedges — liquids (short contracts)	(16,422)	(3,718)
Processing margin hedges — gas (long contracts)	1,714	92
Storage swap transactions (short contracts)	(360)	(29)
Total Mark to market derivatives		$ (771)

* All are gas contracts, volume in MMBtu's, except for processing margin hedges — liquids and liquids swaps (volume in gallons).

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits and monitors the appropriateness of these limits on an ongoing basis. The Partnership primarily deals with two types of counterparties, financial institutions and other energy companies, when entering into financial derivatives on commodities. The Partnership has entered into Master International Swaps and Derivatives Association Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss of $34.5 million would be reduced to $15.2 million due to the netting feature. If the counterparties failed to completely perform according to the terms of the contracts the maximum loss the Partnership would sustain is $15.2 million with other energy companies.

Impact of Cash Flow Hedges

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

	Years Ended December 31,		
Increase (Decrease) in Midstream Revenue	**2009**	**2008**	**2007**
Natural gas	$ 2,156	$ 63	$ 5,533
Liquids	9,707	(10,402)	(4,066)
Realized (gain) loss included in income from discontinued operations	(759)	3,127	(474)
	$ 11,104	$ (7,212)	$ 993

Natural Gas

As of December 31, 2009, there is no remaining balance in accumulated other comprehensive income related to natural gas.

Liquids

As of December 31, 2009, an unrealized derivative fair value net loss of $2.1 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this amount, a $2.1 million loss is expected to be reclassified into earnings through December 2010. 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, 2009	$ (1,098)	$ 316	$ 11	$ (771)

(14) Fair Value Measurements

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

FASB ASC 820 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. The Partnership's contracts are all level two contracts under FASB ASC 820.

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

	Level 2
Interest rate swaps*	$ (24,728)
Commodity swaps*	(2,938)
Total	$ (27,666)

* 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 (loss) also includes the unrealized losses on interest rate swaps of $17.0 million recorded prior to de-designation in January 2008, of which $16.4 million has been recognized in earnings through December 2009.

(15) Transactions with Related Parties

(a) Plants Transferred from Crosstex Energy, Inc.

During 2008 CEI transferred two inactive processing plants to the Partnership at net book value for a cash price of $0.4 million which represented the fair value of the plants.

(b) General and Administrative Expenses

CEI paid the Partnership $0.8 million, $0.7 million and $0.6 million during the years ended December 31, 2009, 2008 and 2007, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI.

(16) Commitments and Contingencies

(a) Leases — Lessee

The Partnership has operating leases for office space, office and field equipment. The Eunice plant operating lease is no longer included in lease obligations. The Partnership acquired the Eunice NGL processing plant and fractionation facility in October 2009, and will no longer have the lease obligation to an outside third party.

The following table summarizes the Partnership's remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in thousands):

2010	$ 15,888
2011	12,111
2012	9,299
2013	6,145
2014	4,702
Thereafter	8,419
	$ 56,564

Operating lease rental expense in the years ended December 31, 2009, 2008 and 2007, was approximately $30.7 million, $39.4 million, and $27.9 million, respectively.

(b) Employment Agreements

Certain members of management of the Partnership are parties to employment contacts with the general partner. The employment agreements provide those senior managers with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

(c) 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, had an active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location was under the oversight of the Louisiana Department of Environmental Quality (LDEQ) and is being conducted under the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. On April 17, 2009, the Partnership completed the remediation and obtained written confirmation from the LDEQ that "no further action" was needed and that the impaired groundwater quality at the Cow Island Gas Processing facility site has been restored to the proper standard. This matter is now officially resolved.

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

(d) Other

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

In December 2008, Denbury Onshore, LLC ("Denbury") initiated formal arbitration proceedings against Crosstex CCNG Processing Ltd. ("Crosstex Processing"), Crosstex Energy Services, L.P. ("Crosstex Energy"), Crosstex North Texas Gathering, L.P. ("Crosstex Gathering") and Crosstex Gulf Coast Marketing Ltd. ("Crosstex Marketing"), all wholly-owned subsidiaries of the Partnership, asserting a claim for breach of contract under a gas processing agreement. Denbury alleged damages in the amount of $16.2 million, plus interest and attorneys' fees. Crosstex denied any liability and sought to have the action dismissed. A three-person arbitration panel conducted a hearing on the merits in December 2009. At the close of the evidence at the hearing, the panel granted judgment for Crosstex on one of Denbury's claims, and on February 16, 2010, the panel granted judgment for Denbury on its remaining claims in the amount of $3.0 million plus interest, attorneys' fees and costs. The panel will conduct additional proceedings to determine the amount of attorneys' fees and costs, if any, that should be awarded to Denbury. The Partnership estimates that the total award will be between $3.0 million and $4.0 million at the conclusion of these additional proceedings. The Partnership has accrued $3.7 million in other current liabilities for this award as of December 31, 2009 and reflected the related expense in purchased gas costs.

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

The Partnership (or its subsidiaries) is defending several lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. 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 \$2.3 million for July 2008 sales. The Partnership believes the July sales of \$2.3 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 \$2.3 million but it remains subject to an objection by the lenders’ agent. The Partnership evaluated these receivables for collectibility and provided a valuation allowance of \$3.1 million and \$0.8 million during the years ended December 31, 2008 and 2009, respectively.

(17) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
2009:					
Revenues	$ 353,158	$ 349,255	$ 350,900	$ 405,777	$ 1,459,090
Operating income	$ 3,619	$ 7,061	$ 8,345	$ 3,627	$ 22,652
Discontinued operations	$ 3,750	$ 4,590	$ 93,461	$ 80,150	$ 181,951
Net income (loss) attributable to the non-controlling interest	$ 32	$ 9	$ (50)	$ 69	$ 60
Net income (loss) attributable to Crosstex Energy, L.P.	$ (15,338)	$ (10,318)	$ 74,189	$ 55,873	$ 104,406
Earnings (loss) per limited partner unit-basic	$ (1.06)	$ (0.19)	$ 1.46	$ 1.09	$ 1.44
Earnings (loss) per limited partner unit-diluted	$ (1.06)	$ (0.19)	$ 1.44	$ 1.07	$ 1.40
Basic and diluted senior subordinated series D unit	$ 8.85	$ —	$ —	$ —	$ 8.85
2008:					
Revenues	$ 799,761	$ 996,832	$ 855,687	$ 423,731	$ 3,076,011
Operating income (loss)	$ 12,464	$ 9,892	$ 4,667	$ (41,183)	$ (14,160)
Discontinued operations	$ 5,551	$ 10,014	$ 6,227	$ 53,020	$ 74,812
Net income (loss) attributable to the non-controlling interest	$ 144	$ 50	$ 44	$ 73	$ 311
Net income (loss) attributable to Crosstex Energy, L.P.	$ 3,711	$ 21,742	$ (5,243)	$ (9,439)	$ 10,771
Earnings (loss) per limited partner unit-basic	$ (3.61)	$ 0.23	$ (0.24)	$ (0.18)	$ (3.19)
Earnings (loss) per limited partner unit-diluted	$ (3.61)	$ 0.21	$ (0.24)	$ (0.18)	$ (3.19)
Basic and diluted senior subordinated series C unit	$ 9.44	$ —	$ —	$ —	$ 9.44

(18) Subsequent Events

The Partnership evaluated events subsequent to the year ended December 31, 2009 through the date of the issuance of the financial statements on February 26, 2010.

Sale of Preferred Units. On January 19, 2010, the Partnership issued approximately $125.0 million of Series A Convertible Preferred Units to the Blackstone / GSO Capital Solutions funds. The preferred units are priced at $8.50 per unit and are convertible at any time into common units on a one-for-one basis, subject to certain adjustments and to its right to force conversion of the preferred units if certain conditions are met. The preferred units will pay a quarterly distribution that will be the greater of $0.2125 per unit or the amount of the quarterly distribution per unit paid to common unitholders, subject to certain adjustments. Such quarterly distribution may be paid in cash, in additional preferred units issued in kind or any combination thereof, provided that the distribution may not be paid in additional preferred units if we pay a cash distribution on common units. The preferred units were issued at a discount to the market price of the common units they are convertible into. This discount totaling $22.3 million represents a beneficial conversion feature that will be reflected as a reduction in common unit equity upon issuance of the preferred units (which occurred on January 19, 2010) and will reduce earnings per common unit.

Disposition of Assets. On January 19, 2010 the Partnership completed the sale of its east Texas assets to a third party for $40.0 million and will recognize a $14.0 million gain on disposition. These assets were not included in discontinued operations nor were they shown as assets held for sale at December 31, 2009 due to the fact they were immaterial to the Partnership.

Long-Term Recapitalization. On February 10, 2010, the Partnership has entered into a new $420.0 million senior secured revolving credit facility with a four-year term and completed the private placement of $725.0 million principal amount of 8.875% senior unsecured notes due February 15, 2018 in a private placement. The Partnership used the net proceeds from the senior unsecured notes offering, together with borrowings under its new credit facility, to repay all borrowings outstanding under its previous revolving credit facility, and retire its senior secured notes and to pay related fees, costs and expenses.

Schedule II

CROSSTEX ENERGY, L.P.

VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
	(In thousands)			
Year ended December 31, 2009 Allowance for doubtful accounts	$ 3,655	$ 1,070	$ 4,315	$ 410
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