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, 2007

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 000-50067

CROSSTEX ENERGY, L.P.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the 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 $343,537,522 on June 29, 2007, based on $35.31 per unit, the closing price of the Common Units as reported on the NASDAQ National Market on such date.

At February 16, 2008, there were 41,484,795 common units and 3,875,340 senior subordinated series D units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

TABLE OF CONTENTS

DESCRIPTION

CROSSTEX ENERGY, L.P.

PART I

Item 1. ***Business***

General

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

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

We have two operating segments, Midstream and Treating. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, while our Treating division focuses on the removal of impurities from natural gas to meet pipeline quality specifications. Our primary Midstream assets include over 5,000 miles of natural gas gathering and transmission pipelines, 12 natural gas processing plants and four fractionators. Our gathering systems consist of a network of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. Our transmission pipelines primarily receive natural gas from our gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. Our processing plants remove NGLs from a natural gas stream and our fractionators separate the NGLs into separate NGL products, including ethane, propane, iso- and normal butanes and natural gasoline. Our primary Treating assets include approximately 225 natural gas amine-treating plants and 55 dew point control plants. Our natural gas treating plants remove carbon dioxide and hydrogen sulfide from natural gas prior to delivering the gas into pipelines to ensure that it meets pipeline quality specifications. See Note 14 to the consolidated financial statements for financial information about these operating segments.

Set forth in the table below is a list of our acquisitions since January 1, 2003.

Acquisition	Acquisition Date	Purchase Price (In thousands)	Asset Type
DEFS Acquisition	June 2003	$ 68,124	Gathering and transmission systems and processing plants
LIG Acquisition	April 2004	73,692	Gathering and transmission systems and processing plants
Crosstex Pipeline Partners	December 2004	5,100	Gathering pipeline
Graco Operations	January 2005	9,257	Treating plants
Cardinal Gas Services	May 2005	6,710	Treating plants and gas processing plants
El Paso Acquisition	November 2005	480,976	Processing and liquids business (including 23.85% interest in Blue Water gas processing plant)
Hanover Amine Treating	February 2006	51,700	Treating plants
Blue Water Acquisition	May 2006	16,454	Additional 35.42% interest in gas processing plant
Chief Acquisition	June 2006	475,287	Gathering and transmission systems and carbon dioxide treating plant
Cardinal Gas Solutions	October 2006	6,330	Dew point control plants and treating plants

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

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

/d = per day
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.

Business Strategy

Our strategy is to increase distributable cash flow per unit by accomplishing economies of scale through new construction or expansion in core operating areas, such as our expansion projects located in north Louisiana and north Texas as discussed in "Recent Acquisitions and Expansion" below; improving the profitability of our assets by increasing their utilization while controlling costs; making accretive acquisitions of assets that are essential to the production, transportation and marketing of natural gas and NGLs; and maintaining financial flexibility to take advantage of opportunities. We believe the expanded scope of our operations, combined with a continued high level of drilling in our principal geographic areas, should present opportunities for continued expansion in our existing areas of operation as well as opportunities to acquire or develop assets in new geographic areas that may serve as a platform for future growth. Key elements of our strategy include the following:

- *Undertaking construction and expansion opportunities ("organic growth").* We leverage our existing infrastructure and producer and customer relationships by constructing new facilities and expanding existing systems to meet new or increased demand for our gathering, transmission, treating, processing and marketing services. In April 2006, we completed construction and commenced operations on our 133-mile North Texas Pipeline, or NTP, to transport gas from the Barnett Shale. In the second quarter of 2007, we expanded the transportation capacity on the NTP from approximately 250 MMcf/d to a total capacity of approximately 375 MMcf/d, and in September 2007, we increased our north Texas processing capacity to a total of approximately 285 MMcf/d with the addition of a 200 MMcf/d cryogenic processing plant, referred to as the Silver Creek plant. We are continuing our build-out of our north Texas facilities in response to the increased producer activity in this area. We currently are constructing a 29-mile natural gas gathering pipeline in north Johnson County, Texas, which we plan to complete in the second quarter of 2008. In April 2007, we also completed construction and commenced operation of a major expansion of the LIG system in north Louisiana that has a total transportation capacity of approximately 250 MMcf/d. We continue to pursue organic growth opportunities in Texas, Louisiana and elsewhere. In 2008, we have budgeted approximately $250 million for various construction and expansion projects planned for 2008, although it is possible that not all of these planned projects will be commenced or completed in 2008.
- *Pursuing accretive acquisitions.* We intend to use our acquisition and integration experience to continue to make strategic acquisitions of midstream and treating 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 have established core areas through the acquisition and consolidation of our south Texas assets in 2001 through 2003, the acquisition of LIG Pipeline Company and subsidiaries, which we collectively refer to as LIG, in 2004, and the acquisition of the south Louisiana processing business from El Paso Corporation, or El Paso, in 2005. 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 .
- *Improving existing system profitability.* After we construct or acquire a new system, we begin an aggressive effort to market services directly to both producers and end users in order to connect new supplies of natural gas, improve margins and more fully utilize the system's capacity. As part of this process, we focus on providing a full range of services to producers and end users, including supply aggregation, transportation and hedging, which we believe provides us with a competitive advantage when we compete for sources of natural gas supply. Treating services are not provided by many of our competitors, which gives us an additional advantage in competing for new supply when gas requires treating to meet pipeline specifications. Furthermore, we emphasize increasing the percentage of our natural gas and NGLs sales directly to end users, such as industrial and utility consumers, in an effort to increase our operating margins.

Recent Acquisitions and Expansion

North Texas Assets. Our NTP, which commenced service in April 2006, consists of a 133-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas. The initial capacity of the NTP was approximately 250 MMcf/d. In 2007, we expanded the capacity on the NTP to a total of approximately 375 MMcf/d. The NTP connects production from the Barnett Shale to markets in north Texas and to markets accessed by the Natural Gas Pipeline Company, or NGPL, Kinder Morgan, Houston Pipeline, or HPL, Atmos and other markets. We are planning to interconnect the NTP with a new interstate gas pipeline to be constructed by Midcontinent Express Pipeline LLC and known as the Midcontinent Express Pipeline. The Midcontinent Express Pipeline is expected to be in service in March 2009. As of December 2007, the total throughput on the NTP was approximately 290,000 MMBtu/d. The NTP also will interconnect with a new intrastate gas pipeline to be constructed by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing Pipeline. We have committed to contract for 150,000 MMBtu/d for ten years of firm transportation capacity on the Gulf Crossing Pipeline when it commences service, which is expected in the fourth quarter of 2008. The Gulf Crossing Pipeline and the Midcontinent Express Pipeline will provide our customers access to premium midwest and east coast markets.

On June 29, 2006, we expanded our operations in the north Texas area through our acquisition of the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems, which we refer to in conjunction with the NTP and our other facilities in the area as our north Texas assets, included gathering pipeline, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that acquisition, approximately 160,000 net acres previously owned by Chief and acquired by Devon Energy Corporation, or Devon, simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. Since the date of the acquisition through December 31, 2007, we had connected 286 new wells to our gathering system and significantly increased the dedicated acreage owned by other producers. In addition, we have a total of 90,000 horsepower of compression to handle the increased volumes and provide low pressure gathering service. In September 2007, we increased our processing capacity in the area by constructing a 200 MMcf/d cryogenic processing plant, referred to as the Silver Creek plant, in addition to our 55 MMcf/d cryogenic processing plant, referred to as our Azle plant, and our 30 MMcf/d processing plant, known as the Goforth plant. We have also installed two 40 gallon per minute and one 100 gallon per minute amine treating plants to provide carbon dioxide removal capability. As of December 2007, the capacity of our north Texas gathering system was approximately 668 MMcf/d and total throughput on our north Texas gathering systems had increased from approximately 115,000 MMBtu/d at the time of the Chief acquisition to approximately 525,000 MMBtu/d.

We currently are constructing a new 29-mile natural gas gathering pipeline in north Johnson County, Texas, to provide greater takeaway capacity to natural gas producers in the Barnett Shale. The system will include low pressure and high pressure gathering pipelines with an estimated system capacity of approximately 400 MMcf/d when all phases of the pipeline are complete, which is planned for the second quarter of 2008. The initial phase of this project was completed in September 2007, and the facilities were transporting approximately 83,000 MMBtu/d in the fourth quarter of 2007.

North Louisiana Expansion Project. In April 2007, we completed construction and commenced operations on our north Louisiana expansion, which is an extension of our LIG system designed to increase take-away pipeline capacity to the producers developing natural gas in the fields south of Shreveport, Louisiana. The north Louisiana expansion consists of approximately 63 miles of 24” mainline with 9 miles of 16” gathering lateral pipeline and 10,000 horsepower of new compression. The capacity of the expansion is approximately 240 MMcf/d, and, as of December 31, 2007, the expansion was flowing at an approximately 225,000 MMBtu/d. Interconnects on the north Louisiana expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission and Trunkline Gas.

Other Developments

Issuance of Common Units. On December 19, 2007, we issued 1,800,000 common units representing limited partner interests 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 this issuance to maintain its 2% general partner interest.

Issuance 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 will 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 will automatically convert into common units on March 23, 2009. The senior subordinated series D units are not entitled to distributions of available cash or allocation of net income/loss from us until March 23, 2009.

Credit Facility. In September 2007, we increased borrowing capacity under our credit facility from $1.0 billion to $1.185 billion.

Midstream Segment

Gathering, Processing and Transmission. Our primary Midstream assets include our north Texas assets, south Texas assets, Louisiana assets, and Mississippi assets. These systems, in the aggregate, consist of over 5,000 miles of pipeline, 12 natural gas processing plants and four fractionators and contributed approximately 85% and 79% of our gross margin in 2007 and 2006, respectively.

- *North Texas Assets.* On June 29, 2006, we acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale. The acquired systems included gathering pipeline, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that transaction, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system.
  - *Gathering System.* Since the date of the acquisition through December 31, 2007, we had connected 286 new wells to our north Texas gathering system and significantly increased the dedicated acreage owned by other producers. In addition, we have a total of 90,000 horsepower of compression to handle the increased volumes and provide low pressure gathering service. As of December 31, 2007, total capacity on our north Texas gathering system was approximately 668 MMcf/d and total throughput was approximately 525,000 MMBtu/d. We are in the process of constructing a new 29-mile natural gas gathering pipeline in north Johnson County, Texas, to provide greater takeaway capacity to natural gas producers in the Barnett Shale. The ultimate capacity of the north Johnson County gathering system is expected to be approximately 400 MMcf/d when all phases of the pipeline are complete, which is planned for the second quarter of 2008.
  - *Processing Facilities.* In September 2007, we increased our processing capacity in north Texas by constructing a 200 MMcf/d cryogenic processing plant, referred to as the Silver Creek plant to complement our 55 MMcf/d cryogenic processing plant, referred to as our Azle plant, and our 30 MMcf/d processing plant, known as the Goforth plant. We have also installed two 40 gallon per minute and one 100 gallon per minute amine treating plants to provide carbon dioxide removal capability.
  - *North Texas Pipeline.* We expanded our NTP system in the second quarter of 2007 to a total capacity of approximately 375 MMcf/day. We are planning to interconnect the NTP with a new interstate gas pipeline to be constructed by Midcontinent Express Pipeline LLC and known as the Midcontinent Express Pipeline. The Midcontinent Express Pipeline is expected to be in service in March 2009. We have committed to contract for 150,000 MMBtu/d of firm transportation capacity on a new interstate gas pipeline to be constructed by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing Pipeline, which will connect with our NTP system in Lamar County, Texas. The Gulf Crossing Pipeline and the Midcontinent Express Pipeline will provide our customers access to premium midwest and east coast markets.
- *South Texas Assets.* We have assembled a highly-integrated south Texas system comprised of approximately 1,400-miles of intrastate gathering and transmission pipelines and a processing plant with a processing capacity of approximately 150 MMcf/day. The south Texas system was built through a number of acquisitions and follow-on organic projects, including acquisitions of the Gulf Coast system, the Corpus Christi system, the Gregory gathering system and processing plant, the Hallmark system and the Vanderbilt system. Average throughput on the system for the year ended December 31, 2007 was approximately 391,000 MMBtu/d, and average throughput for the Gregory and Vanderbilt processing assets was approximately 202,000 MMBtu/d. The system gathers gas from major production areas in the Texas gulf coast and

delivers gas to the industrial markets, power plants, other pipelines and gas distribution companies in the region from Corpus Christi to the Houston area. For continued expansion in this area, we continue to take advantage of existing and to explore new opportunities.

- *Louisiana Assets.* Our Louisiana assets include our LIG intrastate pipeline system and our gas processing and liquids business in south Louisiana, referred to as our south Louisiana processing assets.
  - *LIG System.* The LIG system is the largest intrastate pipeline system in Louisiana, consisting of approximately 2,000 miles of gathering and transmission pipeline, and with an average throughput of approximately 932,000 MMBtu/d for the year ended December 31, 2007. The system also includes two operating, on-system processing plants with an average throughput of 317,000 MMBtu/day for the year ended December 31, 2007. The system has access to both rich and lean gas supplies. These supplies reach from north Louisiana to new offshore production in southeast Louisiana. LIG has a variety of transportation and industrial sales customers, with the majority of its sales being made into the industrial Mississippi River corridor between Baton Rouge and New Orleans. In 2007, we extended our LIG system to the north to reach additional productive areas. This extension, referred to as the north Louisiana expansion or LIG expansion, consists of 63 miles of 24" mainline with 9 miles of gathering lateral pipeline and 10,000 horsepower of compression. The capacity of the expansion is approximately 240 MMcf/d and, as of December 31, 2007, the expansion was flowing at an approximate capacity of 225,000 MMBtu/d.
  - *South Louisiana Processing Assets.* During 2007, we had excess capacity in our south Louisiana facilities. Because production in the Gulf of Mexico has not returned to its pre-hurricanes Katrina and Rita levels, natural gas processing capacity available to the Gulf Coast producers continues to exceed demand. To address this cycle, we have completed a number of operational changes at our Eunice facility and other plants to idle certain equipment, reduce operating expenses and reconfigure operations to manage the lower utilization. In addition, we have increased our focus on upstream markets and opportunities through integration of our LIG system and south Louisiana processing assets to improve our overall performance. As discussed below, operational changes by certain interstate pipelines that supply our plants have had significant impacts on the volumes of gas available to our plants and certain other operational changes by other interstate pipelines are contemplated. Our south Louisiana processing assets, which include a total of 2.3 Bcf/d of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines, include the following:
    - *Eunice Processing Plant and Fractionation Facility.* The Eunice processing plant has a capacity of 1.2 Bcf/d and processed approximately 693,000 MMBtu/d for the year ended December 31, 2007. The plant is connected to onshore gas supply, as well as continental shelf and deepwater gas production and has downstream connections to the ANR Pipeline, Florida Gas Transmission and Texas Gas Transmission, or TGT. TGT modified its system operations in early 2007 in a manner that significantly reduced the volumes available from TGT for processing at the Eunice plant. The Eunice fractionation facility, which was idled in August 2007, has a capacity of 36,000 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. If liquid volumes exceed Riverside's fractionation capacity, the liquids are delivered to a third party for fractionation. This operational change improved overall operating income because of operating cost reductions at the Eunice plant. This facility also has 190,000 barrels of above-ground storage capacity. The fractionation facility produces ethane, propane, iso-butane, normal butane and natural gasoline for various customers. The fractionation facility is directly connected to the southeast propane market and pipelines to the Anse La Butte storage facility.
    - *Pelican Processing Plant.* The Pelican processing plant complex is located in Patterson, Louisiana and has a designed capacity of 600 MMcf/d of natural gas. For the year ended December 31, 2007, the plant processed approximately 330,000 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. For the year ended December 31, 2007, this facility was processing at full capacity.

- *Blue Water Gas Processing Plant.* We acquired a 23.85% interest in the Blue Water gas processing plant in the November 2005 El Paso acquisition and acquired an additional 35.42% interest in May 2006, at which time we became the operator of the plant. The plant has a net capacity to our interest of 186 MMcf/d. For the year ended December 31, 2007, this facility processed approximately 99,000 MMBtu/d net to our interest. The Blue Water plant is located near Crowley, Louisiana. The Blue Water facility is connected to continental shelf and deepwater production volumes through the Blue Water pipeline system. Downstream connections from this plant include the TGP and Columbia Gulf Transmission. The facility also performs liquid natural gas (LNG) conditioning services for the Excelerate Energy LNG tanker unloading facility. TGP is seeking Federal Energy Regulatory Commission, or FERC, approval to acquire Columbia Gulf Transmission's ownership share in the Blue Water pipeline. TGP's operation of the Blue Water pipeline could impact the flow direction around the Blue Water plant and reduce the available gas for processing. We have initiated discussions with TGP to provide an alternative source of gas to our Blue Water plant if the flow of gas is reversed on the Blue Water pipeline. We are also evaluating opportunities to move gas from our LIG system over to our Blue Water plant in addition to seeking new gas sources for this facility.
- *Riverside Fractionation Plant.* The Riverside fractionator and loading facility is located on the Mississippi River upriver from Geismar, Louisiana. The Riverside plant has a fractionation capacity of 28,000 to 30,000 barrels per day of liquids products and fractionates liquids delivered by the Cajun Sibon pipeline system from the Eunice, Pelican, Blue Water and Cow Island 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.
- *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/day. The pipeline transports unfractionated NGLs, referred to as raw make, from the Eunice, Pelican and the Blue Water plants to either the Riverside fractionator or the Napoleonville storage facility. Alternate deliveries can be made to the Eunice plant.

- *Mississippi Assets.* Our Mississippi assets include approximately 600-miles of natural gas gathering and transmission pipelines. The system gathers natural gas from producers, receives and delivers natural gas from and to several major interstate pipelines, including Sonat and Transco, and delivers gas to utilities and industrial end-users. The average system throughput was approximately 116,000 MMBtu/d for the year ended December 31, 2007.

Other Midstream assets and activities include:

- *Arkoma Gathering System.* This approximately 140-mile low-pressure gathering system in southeastern Oklahoma delivers gathered gas into a mainline transmission system. For the year ended December 31, 2007, throughput on the system averaged approximately 18,000 MMBtu/d.
- *East Texas.* Currently our east Texas system, made up of natural gas pipelines and compression installations, gathers and processes natural gas and delivers gas to NGPL, Regency Gas, and to other intrastate pipeline systems. The system is currently near capacity moving approximately 50,000 MMBtu/d, and we have started construction on certain expansion projects to increase the capacity to meet the growing demand in the area.
- *Other.* Other midstream assets consist of a variety of gathering lines and a processing plant with a processing capacity of approximately 66 MMcf/day. Total volumes gathered and resold were approximately 77,000 MMBtu/d for the year ended December 31, 2007. Total volumes processed were approximately 20,000 MMBtu/day in the period.

- *Off-System Services.* We offer natural gas marketing services on behalf of producers for natural gas that does not move on our assets. We market this gas on a number of interstate and intrastate pipelines. These volumes averaged approximately 94,000 MMBtu/d in 2007.

Treating Segment

We operate (or lease to producers for operation) treating plants that remove carbon dioxide and hydrogen sulfide from natural gas before it is delivered into transportation systems to ensure that it meets pipeline quality specifications. Our treating division contributed approximately 15% and 21% of our gross margin in 2007 and 2006, respectively. During 2006, we spent an aggregate of $58.0 million in two separate acquisitions to acquire 55 treating plants, 10 dew point control plants and related spare parts inventory. In 2007, we acquired the remaining ownership interest in seven additional treating plants, in which we already owned a 50% interest, for approximately $1.5 million. At December 31, 2007, we had approximately 190 treating and dewpoint control plants in operation. Pipeline companies have begun enforcing gas quality specifications to lower the dew point of the gas they receive and transport. A higher relative dew point can sometimes cause liquid hydrocarbons to condense in the pipeline and cause operating problems and gas quality issues to the downstream markets. Hydrocarbon dew point plants are skid mounted process equipment that remove these hydrocarbons. Typically these plants use a Joules-Thompson expansion process to lower the temperature of the gas stream and collect the liquids before they enter the downstream pipeline. Our Treating division views dew point control as complementary to our treating business.

We believe we have the largest gas treating operation in the Texas and Louisiana gulf coast. Natural gas from certain formations in the Texas gulf coast, as well as other locations, is high in carbon dioxide, which generally needs to be removed before introduction of the gas into transportation pipelines. Many of our active plants are treating gas from the Wilcox and Edwards formations in the Texas gulf coast, both of which are deeper formations that are high in carbon dioxide. In cases where producers pay us to operate the treating facilities, we either charge a fixed rate per Mcf of natural gas treated or charge a fixed monthly fee.

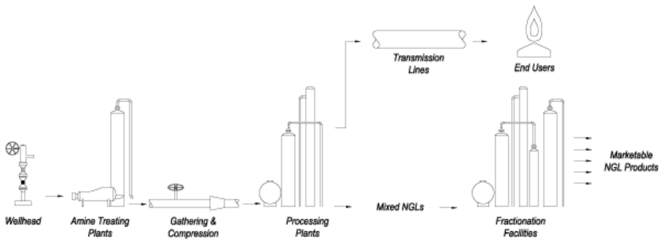
We also own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas. We account for that interest as part of our Treating division. We are not the operator of the plant. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit to which it also supplies carbon dioxide under a long-term arrangement. Revenues at the plant are derived from a fee it charges producers, primarily those at the Seminole San Andres unit, for each Mcf of carbon dioxide returned to the producer for reinjection. The fees currently average approximately $0.68 for each Mcf of carbon dioxide returned. The owners of the Seminole plant also receive 48% of the NGLs produced by the plant. The plant operator has commenced expansion of the plant's capacity, which expansion is expected to be in service in the first quarter of 2009, and as an interest owner in the plant, we are participating in the capital costs for such expansion.

Our treating growth strategy is based on the belief that if gas prices remain at recent levels it will encourage drilling deeper gas formations. We believe the gas recovered from these deep formations is more likely to be high in carbon dioxide, a contaminant that generally needs to be removed before introduction into transportation pipelines. When completing a well, producers place a high value on immediate equipment availability, as they can more quickly begin to realize cash flow from a completed well. We believe our track record of reliability, current availability of equipment and our strategy of sourcing new equipment gives us a significant advantage in competing for new treating business.

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

Industry Overview

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



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

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

Natural gas treating. The composition of natural gas varies depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is high in carbon dioxide. Treating plants are placed at or near a well and remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced into gathering systems and transmission pipelines to ensure that it meets pipeline quality specifications. Pipeline companies have begun enforcing gas quality specifications to lower the dew point of the gas they receive and transport. A higher relative dew point can sometimes cause liquid hydrocarbons to condense in the pipeline and cause operating problems and gas quality issues to the downstream markets. Hydrocarbon dew point plants are skid mounted process equipment that remove these hydrocarbons. Typically these plants use a Joules-Thompson expansion process to lower the temperature of the gas stream and collect the liquids before they enter the downstream pipeline. Our Treating division views dew point control as complementary to our treating business.

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

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

Supply/Demand Balancing

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

Competition

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

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

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

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

Natural Gas Supply

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

Credit Risk and Significant Customers

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

During the year ended December 31, 2007, we had one customer that accounted for approximately 11.8% of our consolidated revenues. While this customer represents a significant percentage of consolidated revenues, the loss of this customer would not have a material impact on our results of operations.

Regulation

Regulation by FERC of Interstate Natural Gas Pipelines. We do not own any interstate natural gas pipelines, so the 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.

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. Rates for services provided under Section 311 of the NGPA may not exceed a "fair and equitable rate", as defined in the NGPA. The rates are generally subject to review every three years by FERC or by an appropriate state agency. Rates for interstate services provided under NGPA Section 311 on our south Texas, Louisiana and Mississippi pipeline systems were reviewed in 2006 and no substantial changes were made to their rates. There were no rate reviews in 2007.

Intrastate Pipeline Regulation. Our intrastate natural gas pipeline operations generally are not subject to rate regulation by FERC, but they 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 state ratable take and common purchaser statutes. The ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply.

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

Environmental Matters

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

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

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

Hazardous Substance and Waste. To a large extent, the environmental laws and regulations affecting our possible future operations relate to the release of hazardous substances or solid wastes into soils, groundwater, and surface water, and include measures to control pollution of the environment. 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. These 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 responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment. Although "petroleum" as well as natural gas and NGLs are excluded from CERCLA's definition of a "hazardous substance," in the course of future, ordinary operations, we may generate wastes that may fall within the definition of a "hazardous substance." We may be responsible under CERCLA 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 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 comparable state statutes. From time to time, the Environmental Protection Agency, or EPA, has considered the adoption of stricter disposal standards for nonhazardous wastes, including crude oil and natural gas wastes. We are not currently required to comply with a substantial portion of the RCRA requirements because our operations generate minimal quantities of hazardous wastes. However, 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 disposal requirements. Changes in applicable regulations may result in an increase in our capital expenditures or plant operating expenses.

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

We acquired our south Louisiana processing assets from El Paso in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, we are working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. As of December 31, 2007, we had incurred approximately $0.5 million in such remediation costs, of which $0.4 million has already been paid. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

We acquired LIG Pipeline Company, and its subsidiaries, on April 1, 2004 from American Electric Power Company (AEP). Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. AEP has indemnified us for these identified sites. Moreover, AEP has entered into an agreement with a third-party company pursuant to which the remediation costs associated with these sites have been assumed by this third-party company that specializes in remediation work. We do not expect to incur any material liability associated with this site.

We acquired assets from Duke Energy Field Services, L.P. (DEFS) in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations had been identified at levels that exceeded the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The estimated remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase and sale agreement, DEFS retained the liability for cleanup of the Conroe site. Moreover, DEFS has entered into an agreement with a third-party company pursuant to which the remediation costs associated with the Conroe site have been assumed by this third-party company that specializes in remediation work. We do not expect to incur any material liability associated with this site.

Air Emissions. Our operations are, and our future operations will likely be subject to the Clean Air Act and comparable state statutes. Amendments to the Clean Air Act were enacted in 1990. Moreover, recent or soon to be adopted changes to state implementation plans for controlling air emissions in regional, non-attainment areas require or will require most industrial operations in the United States to incur capital expenditures in order to meet air emission control standards developed by the EPA and state environmental agencies. As a result of these amendments, our gathering, treating and processing of natural gas, fractionation and storage of NGLs, our facilities therefor or any of our future assets that emit volatile organic compounds or nitrogen oxides may become subject to increasingly stringent regulations, including requirements that some sources install maximum or reasonably available control technology. Such requirements, if applicable to our operations, could cause us to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining governmental approvals addressing air emission related issues. In addition, the 1990 Clean Air Act Amendments established a new operating permit for major sources, which applies to some of the facilities and which may apply to some of our possible future facilities. 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 implementation of the 1990 Clean Air Act Amendments will not have a material adverse effect on our financial condition or operating results.

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

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

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

Transportation. The Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines) amendment to 49 CFR Part 192 (PIM) requires operators of gas transmission pipelines to ensure the integrity of their pipelines through hydrostatic pressure testing, the use of in-line inspection tools or through risk-based direct assessment techniques. In addition, the 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, and, in 2007, we expanded to approximately 25,100 square feet of office space for our south Louisiana operations in Houston, Texas with lease terms expiring in January 2013. In November 2007, we opened 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, 2007, we (through our Operating Partnership) employed approximately 700 full-time employees. Approximately 360 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 occurs, our business, financial condition or results of operations could be affected materially and adversely. In that case, we may be unable to make distributions to our unitholders and the trading price of our common units could decline. These risk factors should be read in conjunction with the other detailed information concerning us set forth in our accompanying financial statements and notes and contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" included herein.

Risks Inherent In Our Business

We may not have sufficient cash after the establishment of cash reserves and payment of our general partner's fees and expenses to enable us to pay the minimum quarterly distribution each quarter.

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

- the amount of natural gas transported in our gathering and transmission pipelines;
- the level of our processing and treating operations;
- the fees we charge and the margins we realize for our services;
- the price of natural gas;

- the relationship between natural gas and NGL prices; and
- our level of operating costs.

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

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

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

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

Our future financial performance will depend, in part, on our ability to make acquisitions of assets and businesses at attractive prices. From time to time, we will 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.

We continue to consider large acquisition candidates and transactions. The integration, financial and other risks discussed above will be amplified if the size of our future acquisitions increases.

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of gas processing and transportation assets by large industry participants. A material decrease in such divestitures will limit our opportunities for future acquisitions and could adversely affect our growth plans.

We are vulnerable to operational, regulatory and other risks associated with our assets including, with respect to our south Louisiana and the Gulf of Mexico, the effects of adverse weather conditions such as hurricanes, because we have a significant portion of our assets located in south Louisiana.

Our operations and revenues will be significantly impacted by conditions in south Louisiana because we have a significant portion of our assets located in south Louisiana. This concentration of activity make us more vulnerable than many of our competitors to the risks associated with Louisiana and the Gulf of Mexico, 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 a more diversified geographic area.

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.

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. These risks are based upon three components of our business: (1) we purchase certain volumes of natural gas at a price that is a percentage of a relevant index; (2) certain processing contracts for our Gregory system and our Plaquemine and Gibson processing plants expose us to natural gas and NGL commodity price risks; and (3) part of our fees from our Conroe and Seminole gas plants as well as those acquired in the El Paso acquisition are based on a portion of the NGLs produced, and, therefore, is subject to commodity price risks.

The margins we realize from purchasing and selling a portion of the natural gas that we transport through our pipeline systems decrease in periods of low natural gas prices because our gross margins related to such purchases are based on a percentage of the index price. For the years ended December 31, 2006 and 2007, we purchased approximately 5.9% and 4.3%, respectively, of our gas at a percentage of relevant index. Accordingly, a decline in the price of natural gas could have an adverse impact on our results of operations.

A portion of our profitability is affected by the relationship between natural gas and NGL prices. For a component of our Gregory system and our Plaquemine plant and Gibson plant volumes, we purchase natural gas, process natural gas and extract NGLs, and then sell the processed natural gas and NGLs. A portion of our profits from the plants acquired in the El Paso acquisition is dependent on NGL prices and elections by us and the producers. In cases where we process gas for producers when they have the ability to decide whether to process their gas, we may elect to receive a processing fee or we may retain and sell the NGLs and keep the producer whole on its sale of natural gas. Since we extract energy content, which we measure in Btus, from the gas stream in the form of the liquids or consume it as fuel during processing, we reduce the Btu content of the natural gas. Accordingly, our margins under these arrangements can be negatively affected in periods in which the value of natural gas is high relative to the value of NGLs.

In the past, the prices of natural gas and NGLs have been extremely volatile and we expect this volatility to continue. For example, in 2006, the NYMEX settlement price for natural gas for the prompt month contract ranged from a high of $11.43 per MMBtu to a low of $4.20 per MMBtu. In 2007, the same index ranged from $7.59 per MMBtu to $5.43 per MMBtu. A composite of the OPIS Mt. Belvieu monthly average liquids price based upon our average liquids composition in 2006 ranged from a high of approximately $1.20 per gallon to a low of approximately $0.90 per gallon. In 2007, the same composite ranged from approximately $1.58 per gallon to approximately $0.92 per gallon. As further discussed below in Management’s Discussion and Analysis of Financial

Condition and Results of Operations our processing facilities realized favorable processing margins during 2007, but due to this volatility in the prices of natural gas and NGLs, processing margins may be lower in future periods if NGL markets weaken.

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

The markets and prices for residue gas and NGLs depend upon factors beyond our control. These factors include demand for oil, natural gas and NGLs, which 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;
- the level of domestic industrial and manufacturing activity;
- the availability of imported oil and natural gas;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

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

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

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

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

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

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

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

We have limited control over the development of certain assets because we are not the operator.

As the owner of non-operating interests in the Seminole processing plant, we do not have the right to direct or control the operation of the plant. As a result, the success of the activities conducted at this plant, which is operated by a third party, may be affected by factors outside of our control. The failure of the third-party operator to make decisions, perform its services, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations affecting this plant, including environmental laws and regulations, in a proper manner could result in material adverse consequences to our interest and adversely affect our results of operations.

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.

As 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 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. Any increase in the nonpayment and nonperformance by our customers could adversely affect our results of operations.

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

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

For the year ended December 31, 2007, approximately 53% of our sales of gas which were transported using our physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with us in the marketing of natural gas, we often compete in the end-user and utilities markets primarily on the basis of price. The inability of our management to renew or replace our current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on our profitability.

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

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

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

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

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

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

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

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

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

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

While the FERC generally does not regulate our operations, it influences certain aspects of our business and the market for our products. The rates, terms and conditions of service under which we transport natural gas in our pipeline systems in interstate commerce are subject to FERC regulation under the Section 311 of the NGPA. Our intrastate natural gas pipeline operations generally are not subject to rate regulation by FERC, but they 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.

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

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

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

Compliance with pipeline integrity regulations issued by the United States Department of Transportation in December of 2003 or those issued by the TRRC could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. Our costs relating to compliance with the required testing under the TRRC regulations were approximately $1.2 million, $1.1 million and $0.3 million for the years ended December 31, 2007, 2006 and 2005, respectively. We expect the costs for compliance with TRRC and DOT regulations to be $8.9 million during 2008. 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, populated areas, such as the Barnett Shale, we will have to comply with local ordinances and other restrictions imposed by cities and towns, such as noise ordinances and restrictions on facility locations and pressures. These requirements could result in increased costs and construction delays.

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

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

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

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

Our use of derivative financial instruments has in the past and could in the future result in financial losses or reduce our income.

We use over-the-counter price and basis swaps with other natural gas merchants and financial institutions, interest rate swaps with financial institutions and futures and option contracts traded on the New York Mercantile Exchange. Use of these instruments is intended to reduce our exposure to short-term volatility in commodity prices and interest rates. We could incur financial losses or fail to recognize the full value of a market opportunity as a result of volatility in the market values of the underlying commodities or if one of our counterparties fails to perform under a contract.

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

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

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

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

Risk Inherent in an Investment in the Partnership

Crosstex Energy, Inc. controls our general partner and owned a 36% limited partner interest in us as of December 31, 2007. Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor its own interests.

As of December 31, 2007, Crosstex Energy, Inc. indirectly owned an aggregate limited partner interest of approximately 36% in us. In addition, CEI owns and controls our general partner. Due to its control of our general partner and the size of its limited partner interest in us, CEI effectively controls all limited partnership decisions, including any decisions related to the removal of our general partner. Conflicts of interest may arise in the future between CEI and its affiliates, including our general partner, on the one hand, and our partnership, on the other hand. As a result of these conflicts our general partner may favor its own interests and those of its affiliates over our interests. These conflicts include, among others, the following situations:

Conflicts Relating to Control

- our partnership agreement limits our general partner's liability and reduces its fiduciary duties, while also restricting the remedies available to our unitholders for actions that might, without these limitations, constitute breaches of fiduciary duty by our general partner;
- in resolving conflicts of interest, our general partner is allowed to take into account the interests of parties in addition to unitholders, which has the effect of limiting its fiduciary duties to the unitholders;
- our general partner's affiliates may engage in limited competition with us;
- our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- in some instances our general partner may cause us to borrow funds from affiliates of the general partner or from third parties in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on our subordinated units or to make incentive distributions or hasten the expiration of the subordination period; and
- our partnership agreement gives our general partner broad discretion in establishing financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution. Our general partner may establish reserves for distribution on our subordinated units, but only if those reserves will not prevent us from distributing the full minimum quarterly distribution, plus any arrearages, on the common units for the following four quarters.

Conflicts Relating to Costs:

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

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

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

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

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. The general partner generally may not be removed except upon the vote of the holders of 66$^{2}/_{3}$% of the outstanding units voting together as a single class. Because affiliates of the general partner controlled approximately 37% of all the units as of December 31, 2007, the general partner could not be removed without the consent of the general partner and its affiliates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Tax Risks to Our Unitholders

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress are considering substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Specifically, federal income tax legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships and recharacterize certain types of income received from partnerships. Although the currently proposed legislation would not appear to affect our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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

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

We will adopt certain methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. Because the determination of value and the allocation of value are factual matters, rather than legal matters, our counsel is unable to opine as to these matters. The IRS may challenge our valuation methods, our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and/or the allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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

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

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

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

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

We do not have any unresolved staff comments.

Item 2. ***Properties***

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

Title to Properties

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

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

Item 3. ***Legal Proceedings***

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

On November 15, 2007, Crosstex CCNG Processing Ltd. ("Crosstex CCNG"), our wholly-owned subsidiary, received a demand letter from Denbury Onshore, LLC ("Denbury"), asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. The claim arises from a contract under which Crosstex CCNG processed natural gas owned or controlled by Denbury in north Texas. Denbury contends that Crosstex CCNG breached the contract by failing to build a processing plant of a certain size and design, resulting in Crosstex CCNG's failure to properly process the gas over a ten month period. Denbury also alleges that Crosstex CCNG failed to provide specific notices required under the contract. On December 4, 2007 and again on February 14, 2008, Denbury sent Crosstex CCNG letters demanding that its claim be arbitrated pursuant to an arbitration provision in the contract. Denbury subsequently requested that the parties attempt to mediate the matter before any arbitration proceeding is initiated. Although it is not possible to predict with certainty the ultimate outcome of this matter, we do not believe this will have a material adverse effect on our consolidated results of operations or financial position.

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

No matters were submitted to security holders during the fourth quarter of the year ended December 31, 2007.

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, 2008, the market price for the common units was $30.43 per unit (based upon the closing price on the immediately preceding trading day) and there were approximately 10,288 record holders and beneficial owners (held in street name) of our common units and nine record holders of our 3,875,340 senior subordinated D units. There is no established public trading market for our senior subordinated series D units.

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

	Common Unit Price Range(a)		Cash Distribution
	High	Low	Paid per Unit(a)
2007:			
Quarter Ended December 31	$ 34.91	$ 31.02	$ 0.61
Quarter Ended September 30	38.27	32.78	0.59
Quarter Ended June 30	36.45	33.56	0.57
Quarter Ended March 31	39.56	33.49	0.56
2006:			
Quarter Ended December 31	$ 39.85	$ 35.17	$ 0.56
Quarter Ended September 30	37.94	35.17	0.55
Quarter Ended June 30	38.10	33.57	0.54
Quarter Ended March 31	37.30	34.15	0.53

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

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 percent 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 percent, 23 percent and 48 percent based on incremental distribution thresholds as set forth in our partnership agreement.

Our ability to distribute available cash is contractually restricted by the terms of our credit facility. Our credit facility contains covenants requiring us to maintain certain financial ratios. We are prohibited from making any distributions to unitholders if the distribution would cause an event of default, or an event of default is existing, under our credit facility. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Description of Indebtedness."

Conversion of Senior Subordinated Series D Units

The 3,875,340 senior subordinated series D units are scheduled to convert into common units at a ratio of one common unit for each senior subordinated series D unit in March 2009, subject to adjustment depending on the achievement of financial metrics in the fourth quarter 2008 as outlined in the Partnership Agreement.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants, and Rights (a)	Weighted-Average Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plan (Excluding Securities Reflected in Column (a)) (c)
Equity Compensation Plans Approved By Security Holders	N/A	N/A	N/A
Equity Compensation Plans Not Approved By Security Holders	1,611,827(1)(2)	$ 29.65(3)	2,567,340

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

(2) The number of securities includes (i) 459,791 restricted units that have been granted under our long-term incentive plan that have not vested, and (ii) 44,727 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, 2007 range from $10.00 to $37.31 per unit.

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

The following table sets forth selected historical financial and operating data of Crosstex Energy, L.P. as of and for the dates and periods indicated. The selected historical financial data are derived from the audited financial statements of Crosstex Energy, L.P. In addition, our summary historical financial and operating data include the results of operations of the Mississippi pipeline system and Seminole processing plant beginning in June 2003, the LIG assets beginning in April 2004, the Graco assets beginning January 2005, the Cardinal assets beginning May 2005, the south Louisiana processing assets beginning November 1, 2005, the Hanover assets beginning January 2006, the NTP beginning April 2006 and the Chief midstream assets beginning June 29, 2006 and other smaller acquisitions completed in 2006.

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

	Crosstex Energy, L.P. Years Ended December 31,				
	2007	2006	2005	2004	2003
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Midstream	$ 3,791,316	$ 3,075,481	$ 2,982,874	$ 1,948,021	$ 989,697
Treating	65,025	63,813	48,606	30,755	23,966
Profit on energy trading activities	4,090	2,510	1,568	2,228	2,266
Total revenues	3,860,431	3,141,804	3,033,048	1,981,004	1,015,929
Operating costs and expenses:					
Midstream purchased gas	3,468,924	2,859,815	2,860,823	1,861,204	946,412
Treating purchased gas	7,892	9,463	9,706	5,274	7,568
Operating expenses	127,759	100,991	56,736	38,340	19,814
General and administrative(1)	61,528	45,694	32,697	20,866	10,067
(Gain) loss on derivatives	(5,666)	(1,599)	9,968	(279)	361
Gain on sale of property	(1,667)	(2,108)	(8,138)	(12)	—
Depreciation and amortization	108,880	82,731	36,024	23,034	13,268
Total operating costs and expenses	3,767,650	3,094,987	2,997,816	1,948,427	997,490
Operating income	92,781	46,817	35,232	32,577	18,439
Other income (expense):					
Interest expense, net	(78,451)	(51,427)	(15,767)	(9,220)	(3,392)
Other income (expense)	683	183	392	798	179
Total other income (expense)	(77,768)	(51,244)	(15,375)	(8,422)	(3,213)
Income before minority interest and taxes	15,013	(4,427)	19,857	24,155	15,226
Minority interest	(160)	(231)	(441)	(289)	—
Federal income taxes	(964)	(222)	(216)	(162)	—
Income (loss) before cumulative effect of change in accounting principle	13,889	(4,880)	19,200	23,704	15,226
Cumulative effect of change in accounting principle	—	689	—	—	—
Net income (loss)	$ 13,889	$ (4,191)	$ 19,200	$ 23,704	$ 15,226
Net income (loss) per limited partner unit — basic	$ (0.20)	$ (1.09)	$ 0.56	$ 0.98	$ 0.89
Net income (loss) per limited partner unit — diluted	$ (0.20)	$ (1.09)	$ 0.51	$ 0.95	$ 0.88
Net income (loss) per limited partner senior subordinated unit — basic and diluted	—	$ 5.31	—	—	—
Distributions per limited partner unit(2)	$ 2.33	$ 2.18	$ 1.93	$ 1.70	$ 1.25

	Crosstex Energy, L.P. Years Ended December 31,				
	2007	2006	2005	2004	2003
	(In thousands, except per unit data)				
Balance Sheet Data (end of period):					
Working capital deficit	$ (46,888)	$ (79,936)	$ (11,681)	$ (34,724)	$ (4,572)
Property and equipment, net	1,425,162	1,105,813	667,142	324,730	203,909
Total assets	2,592,874	2,194,474	1,425,158	586,771	366,050
Long-term debt	1,223,118	987,130	522,650	148,700	60,750
Partners' equity	784,826	711,877	401,285	144,050	154,610
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 114,818	$ 113,010	$ 14,010	$ 48,103	$ 46,460
Investing activities	(411,382)	(885,825)	(615,017)	(124,371)	(110,289)
Financing activities	295,882	772,234	596,615	81,899	62,687
Other Financial Data:					
Midstream gross margin	$ 326,482	$ 218,176	$ 123,619	$ 89,045	$ 45,551
Treating gross margin	57,133	54,350	38,900	25,481	16,398
Total gross margin(3)	$ 383,615	$ 272,526	$ 162,519	$ 114,526	$ 61,949
Operating Data:					
Pipeline throughput (MMBtu/d)	2,118,000	1,356,000	1,126,000	1,289,000	626,000
Natural gas processed (MMBtu/d)(4)	2,057,000	2,032,000	1,921,000	425,000	132,000
Producer Services (MMBtu/d)	94,000	138,000	175,000	210,000	259,000

(1) For the year ended December 31, 2003, the amount for which our general partner was entitled to reimbursement from us for allocated general and administrative expenses was limited to $6.0 million. Such limitation did not apply to expenses incurred in connection with acquisitions or business development opportunities evaluated on our behalf.

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

(3) Gross margin is defined as revenue, including treating fee revenues and profit on energy trading 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. We have two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. Our Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, while our Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the year ended December 31, 2007, approximately 85% of our gross margin was generated in the Midstream division with the balance in the Treating division. We manage our operations by focusing on gross margin because our business is generally to purchase and resell gas for a margin, or to gather, process, transport, market or treat gas or NGLs for a fee. We buy and sell most of our gas at a fixed relationship to the relevant index price so our margins on gas sales are not significantly affected by changes in gas prices. 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. As explained under "Commodity Price Risk" below, we enter into financial instruments to reduce volatility in our gross margin due to price fluctuations.

During the past five years we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2003 through December 31, 2007, we have invested over $2.1 billion to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

Our Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through our pipeline systems, processed at our processing facilities, and the volumes of NGLs handled at our fractionation facilities. Our Treating segment margins are largely a function of the number and size of treating plants in operation and fees earned for removing impurities from NGLs at a non-operated processing plant. We generate revenues from six primary sources:

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

The bulk of our operating profits has historically been derived from the margins we realize for gathering and transporting natural gas and NGLs through our pipeline systems. Generally, we either gather or transport gas owned by others through our facilities for a fee, or we buy gas from a producer, plant or transporter at either a fixed discount to a market index or a percentage of the market index, then transport and resell the gas. In our purchase/sale transactions, the resale price is generally based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. See "Commodity Price Risk" below for a discussion of how we manage our business to reduce the impact of price volatility.

Processing and fractionation revenues are largely fee based. Our processing fees are largely based on either a percentage of the liquids volume recovered, or a fixed fee per unit processed. Fractionation and marketing fees are generally fixed fee per unit of products.

We generate treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 28% and 32% of the operating income in our Treating division for the years ended December 31, 2007 and 2006, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 48% and 48% of the operating income in our Treating division for the years ended December 31, 2007 and 2006, respectively; or

- a fee arrangement in which the producer operates the plant, which accounted for approximately 24% and 20% of the operating income in our Treating division for the years ended December 31, 2007 and 2006, respectively.

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

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

Acquisitions and Expansions

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

On June 29, 2006, we expanded our operations in the north Texas area through our acquisition of the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems, which we refer to in conjunction with the NTP and our other facilities in the area as our north Texas assets, included gathering pipeline, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that acquisition, approximately 160,000 net acres previously owned by Chief and acquired by Devon Energy Corporation, or Devon, simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our north Texas pipeline gathering system. Since the date of the acquisition through December 31, 2007, we had connected 286 new wells to our gathering system and significantly increased the dedicated acreage owned by other producers. In addition, we have a total of 90,000 horsepower of compression to handle the increased volumes and provide low pressure gathering service. In September 2007, we increased our processing capacity in the area by constructing a 200 MMcf/d cryogenic processing plant, referred to as the Silver Creek plant, in addition to our 55 MMcf/d cryogenic processing plant, referred to as our Azle plant, and our 30 MMcf/d processing plant, known as the Goforth plant. We have also installed two 40 gallon per minute and one 100 gallon per minute amine treating plants to provide carbon dioxide removal capability. We have a total capacity of approximately 668 MMcf/d on our north Texas gathering assets and have increased total throughput on our north Texas gathering systems from approximately 115,000 MMBtu/d at the time of the Chief acquisition to approximately 525,000 MMBtu/d for the month of December 2007.

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

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

Our NTP, which commenced service in April 2006, consists of a 133-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas. The initial capacity of the NTP was approximately 250 MMcf/d. In 2007, we expanded the capacity on the NTP to a total of approximately 375 MMcf/d. The NTP connects production from the Barnett Shale to markets in north Texas and to markets accessed by the Natural Gas Pipeline Company, or NGPL, Kinder Morgan, Houston Pipeline, or HPL, Atmos and other markets. As of December 2007, the total throughput on the NTP was approximately 290,000 MMBtu/d. The NTP will interconnect with a new intrastate gas pipeline to be constructed by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing Pipeline. The Gulf Crossing Pipeline will provide our customers access to premium midwest and east coast markets. We have committed to contract for 150,000 MMBtu/d for ten years of firm transportation capacity on the Gulf Crossing Pipeline when it commences service, which is expected in the fourth quarter of 2008.

We currently are constructing a new 29-mile natural gas gathering pipeline in north Johnson County, Texas, to provide greater takeaway capacity to natural gas producers in the Barnett Shale. The system will include low pressure and high pressure gathering pipelines with an estimated system capacity of approximately 400 MMcf/d when all phases of the pipeline are complete, which is planned for the second quarter of 2008. The initial phase of this project was completed in September 2007, and the facilities were transporting approximately 83,000 MMBtu/d in the fourth quarter of 2007.

In April 2007, we completed construction and commenced operations on our north Louisiana expansion, which is an extension of our LIG system designed to increase take-away pipeline capacity to the producers developing natural gas in the fields south of Shreveport, Louisiana. The north Louisiana expansion consists of approximately 63 miles of 24" mainline with 9 miles of 16" gathering lateral pipeline and 10,000 horsepower of new compression. The capacity of the expansion is approximately 240 MMcf/d, and, as of December 31, 2007, the expansion was flowing at approximately 225,000 MMBtu/d. Interconnects on the north Louisiana expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission and Trunkline Gas.

Commodity Price Risk

Our profitability has been and will continue to be affected by volatility in prevailing NGL product and natural gas prices. Changes in the prices of NGL products can correlate closely with changes in the price of crude oil. NGL product and natural gas prices have been subject to significant volatility in recent years in response to changes in the supply and demand for crude oil, NGL products and natural gas.

Profitability under our gas processing contracts is impacted by the margin between NGL sales prices and the cost of natural gas and may be negatively affected by decreases in NGL prices or increases in natural gas prices. Changes in natural gas prices impact our profitability since the purchase price of a portion of the gas we buy is based on a percentage of a particular natural gas price index for a period, while the gas is resold at a fixed dollar relationship to the same index. Therefore, during periods of low gas prices, these contracts can be less profitable than during periods of higher gas prices. However, on most of the gas we buy and sell, margins are not affected by such changes because the gas is bought and sold at a fixed relationship to the relevant index. Therefore, while changes in the price of gas can have very large impacts on revenues and cost of revenues, the changes are equal and offsetting.

Set forth in the table below is the volume of the natural gas purchased and sold at a fixed discount or premium to the index price and at a percentage discount or premium to the index price for our principal gathering and transmission systems and for our commercial services business for the year ended December 31, 2007.

	Year Ended December 31, 2007			
	Gas Purchased		Gas Sold	
Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(In thousands of MMBtu's)			
LIG system(2)	223,378	5,256	228,635	—
South Texas system(1)	139,660	12,886	136,168	—
North Texas system	67,914	2,247	70,082	—
Other assets and activities(1)	81,752	2,890	49,669	—

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

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

We estimate that, due to the gas that we purchase at a percentage of index price, for each $0.50 per MMBtu increase or decrease in the price of natural gas, our gross margins increase or decrease by approximately $1.0 million on an annual basis (before consideration of our hedge positions). As of December 31, 2007, we have hedged approximately 95% of our exposure to such fluctuations in natural gas prices in 2008 and approximately 34% of our exposure to such fluctuations in 2009. We may continue to hedge our exposure to gas prices when market opportunities appear attractive.

During 2007, we processed approximately 75% of our volume at our Eunice, Pelican, Sabine and Blue Water plants under “percent of proceeds” contracts, under which we receive as a fee a portion of the liquids produced, and 25% of our volume as fixed fee per unit processed. Under percent of proceeds contracts, we are exposed to changes in the prices of NGLs. For the years 2006 and 2007, we have purchased puts or entered into forward sales covering all of our anticipated minimum share of NGLs production. For 2008, we have hedges in place covering approximately 80% of the liquid volumes we expect to receive through May 2008.

Our processing plants at Plaquemine and Gibson have a variety of processing contract structures. In general, we buy gas under keep-whole arrangements in which we bear the risk of processing, percentage-of-proceeds arrangements in which we receive a percentage of the value of the liquids recovered, and “theoretical” processing arrangements in which the settlement with the producer is based on an assumed processing result. Because we have the ability to bypass certain volumes or revert to minimum fee arrangements when processing is uneconomic, we can limit our exposure to adverse processing margins. During periods when processing margins are favorable, we can substantially increase the volumes we are processing.

For the year ended December 31, 2007, we purchased a small amount (approximately 3.3%) of the natural gas volumes on our Gregory system under contracts in which we were exposed to the risk of loss or gain in processing the natural gas. The remaining approximately 96.7% of the natural gas volumes on our Gregory system were purchased at a spot or market price less a discount that includes a fixed margin for gathering, processing and marketing the natural gas and NGLs at our Gregory processing plant with no risk of loss or gain in processing the natural gas.

We own an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies carbon dioxide under a long-term arrangement. Revenues at the plant are derived from a fee it charges producers, including those at the Seminole San Andres unit, for each Mcf of carbon dioxide returned to the producer for reinjection. The fees currently average approximately $0.68 for each Mcf of carbon dioxide returned. Reinjected carbon dioxide is used in a tertiary oil recovery process in the field. The plant also receives 48% of the NGLs produced by the plant. Therefore, we have commodity price exposure due to variances in the prices of NGLs. During 2007, our share of NGLs totaled approximately 5.2 million gallons at an average price of $1.23 per gallon.

Gas prices can also affect our profitability indirectly by influencing drilling activity and related opportunities for gas gathering, treating and processing.

Results of Operations

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

	Years Ended December 31,		
	2007	2006	2005
		(Dollars in millions)	
Midstream revenues	$ 3,791.3	$ 3,075.5	$ 2,982.9
Midstream purchased gas	(3,468.9)	(2,859.8)	(2,860.8)
Profits on energy trading activities	4.1	2.5	1.6
Midstream gross margin	326.5	218.2	123.7
Treating revenues	65.0	63.8	48.6
Treating purchased gas	(7.9)	(9.5)	(9.7)
Treating gross margin	57.1	54.3	38.9
Total gross margin	$ 383.6	$ 272.5	$ 162.6
Midstream Volumes (MMBtu/d):			
Gathering and transportation	2,118,000	1,356,000	1,126,000
Processing	2,057,000	2,032,000	1,921,000
Producer services	94,000	138,000	175,000
Treating Plants in Operation at Year-end	190	190	112

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

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

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

The favorable processing margins we realized during 2007 at several of our processing facilities may be higher than margins we may realize during 2008 and future periods if the NGL markets do not remain as strong as they were during 2007. As discussed above under "*-Commodity Price Risk*", we receive as a processing fee a percentage of the liquids recovered on a substantial portion of the gas processed through our plants. Also, during periods when processing margins are favorable due to liquids prices being high relative to natural gas prices, as existed during 2007, we have the ability to generate higher processing margins. We have the ability to bypass certain volumes when processing is uneconomic so we can avoid negative processing margins but our margins will be lower during these periods.

In addition, we have the ability to buy gas from and to sell gas to various gas markets through our pipeline systems. During 2007 we were able to benefit from price differentials between the various gas markets by selling gas into markets with more favorable pricing thereby improving our Midstream gross margin. If these price differentials do not exist during future periods, our Midstream gross margin may be lower.

Treating gross margin was $57.1 million for the year ended December 31, 2007 compared to $54.3 million for the same period in 2006, an increase of $2.8 million, or 5.1%. There were approximately 190 treating and dew point control plants in service at December 31, 2007. Although the number of plants in service was unchanged from December 31, 2006, gross margin growth for 2007 is attributed to a higher average number of plants in service each month during 2007 compared to 2006.

Operating Expenses. Operating expenses were $127.8 million for the year ended December 31, 2007 compared to $101.0 million for the year ended December 31, 2006, an increase of $26.8 million, or 26.5%. The increase in operating expenses primarily reflects costs associated with growth and expansion in the north Texas assets of $17.5 million, the south Texas assets of $1.8 million, LIG and the north Louisiana expansion of $3.7 million and Treating assets of $1.6 million. Operating expenses included $1.8 million of stock-based compensation expense in 2007 compared to $1.1 million of stock-based compensation expense in 2006.

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

Gain/Loss on Derivatives. We had a gain on derivatives of $5.7 million for the year ended December 31, 2007 compared to a gain of $1.6 million for the year ended December 31, 2006. The gain in 2007 includes a gain of $8.1 million associated with our basis swaps (including $7.0 million of realized gain) plus a net gain associated with storage financial transactions, third-party on-system and off-system financial transactions and ineffectiveness in our hedged derivatives of $0.6 million partially offset by a loss of $1.3 million associated with our processing margin hedges (all realized), a loss of $0.9 million related to our interest rate swaps and a loss of $0.8 million on puts acquired in 2005 related to the acquisition of the south Louisiana processing assets. As of December 31, 2007, the fair value of the puts was zero as all the put options have expired.

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

Depreciation and Amortization. Depreciation and amortization expenses were $108.9 million for the year ended December 31, 2007 compared to $82.7 million for the year ended December 31, 2006, an increase of $26.2 million, or 31.6%. Midstream depreciation and amortization increased $25.8 million due to the NTP, NTG and north Louisiana expansion project assets.

Interest Expense. Interest expense was $78.5 million for the year ended December 31, 2007 compared to $51.4 million for the year ended December 31, 2006, an increase of $27.0 million. The increase relates primarily to an increase in debt outstanding as a result of acquisitions and other growth projects. Interest rate changes between periods was not significant. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2007	2006
Senior notes	$ 33.4	$ 23.6
Credit facility	47.2	30.1
Other	3.9	4.3
Capitalized interest	(4.8)	(5.4)
Realized interest rate swap gains	(0.5)	(0.1)
Interest income	(0.7)	(1.1)
Total	$ 78.5	$ 51.4

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $218.2 million for the year ended December 31, 2006 compared to $123.7 million for the year ended December 31, 2005, an increase of $94.6 million, or 76.5%. This increase was primarily due to acquisitions, increased system throughput and a favorable processing environment for natural gas and natural gas liquids.

The south Louisiana processing assets acquired in November 2005 contributed $56.1 million to Midstream gross margin growth in 2006. This amount was driven by the three largest processing plants, Eunice, Pelican and Sabine Pass, which contributed gross margin increases of $25.1 million, $11.4 million and $9.1 million, respectively. The Riverside fractionation facility and the Blue Water plant also contributed gross margin growth to the south Louisiana operations of $5.1 million and $3.7 million, respectively. Operational improvements and volume increases on the LIG system contributed margin growth of $12.5 million during 2006. Increased processing volumes at the Gibson and Plaquemine plants due to drilling successes by producers and increased unit margins due to favorable NGL markets accounted for a $9.5 million increase in gross margin. We acquired the north Texas gathering system from Chief in June 2006. This gathering system and related facilities contributed $11.7 million of gross margin during 2006. The NTP commenced operation during the second quarter of 2006 and contributed $8.0 million in gross margin. These gains were partially offset by volume and margin declines on our southern region assets. Decreased throughput on the south Texas systems contributed to an overall margin decrease in our southern region of $6.9 million.

Treating gross margin was $54.3 million for the year ended December 31, 2006 compared to $38.9 million for the year ended December 31, 2005, an increase of $15.5 million, or 39.7%. Treating plants in service increased from 112 plants at December 2005 to 160 plants (excluding 30 dew point control plants in service) at December 2006. The increase in the number of plants in service is primarily due to the acquisition of the amine treating assets from Hanover Compressor Company in February of 2006. New plants associated with the Hanover acquisition contributed $7.4 million in gross margin growth. The field services also acquired from Hanover contributed $1.0 million in gross margin for the year. Plant additions from inventory and expansion projects at existing plants contributed gross margin growth of $6.6 million and $0.5 million, respectively. The Seminole plant contributed $1.5 million of gross margin growth due to the recalculation of fees based on rate escalations set forth in the contract. The acquisition and installation of dew point control plants contributed an additional $0.7 million increase to gross margin.

Operating Expenses. Operating expenses were $101.0 million for the year ended December 31, 2006 compared to $56.7 million for the year ended December 31, 2005, an increase of $44.3 million, or 78%. The increase in operating expenses related to asset acquisitions and the related engineering and technical service support needed for the asset growth. Our Treating segment accounted for approximately $4.8 million of the increase with the remaining increase resulting from growth in our Midstream assets. Operating expenses included stock-based compensation expenses of $1.1 million and $0.4 million for the years ended December 31, 2006 and 2005, respectively.

General and Administrative Expenses. General and administrative expenses were $45.7 million for the year ended December 31, 2006 compared to $32.7 million for the year ended December 31, 2005, an increase of $13.0 million, or 40%. Staffing and office infrastructure costs required for support of Midstream and Treating asset acquisitions accounted for the increase. General and administrative expenses included stock-based compensation expense of $7.4 million and $3.7 million for the year ended December 31, 2006 and 2005, respectively. The $3.8 million increase in stock-based compensation, determined in accordance with FAS 123R during 2006 and in accordance with APB25 in 2005, primarily relates to an increase in restricted stock and unit grants due to an increase in the pool of eligible participants.

Gain/Loss on Derivatives. We had a gain on derivatives of $1.6 million for the year ended December 31, 2006 compared to a loss of $10.0 million for the year ended December 31, 2005. The gain in 2006 includes a gain of $2.9 million on storage financial transactions (including $0.7 million of realized gain), a gain of $0.7 million associated with our basis swaps (including $0.4 million of realized gain), a gain of $1.5 million associated with derivatives for third-party on-system financial transactions (including $1.2 million of realized gains), and a gain of $0.1 million due to ineffectiveness in our hedged derivatives partially offset by a loss of $3.6 million on puts acquired in 2005 related to the acquisition of the south Louisiana processing assets. As of December 31, 2006, the fair value of the puts was $1.7 million. The loss in 2005 includes a $9.2 million loss on the puts related to the acquisition of the South Louisiana Processing Assets.

Gain/Loss on Sale of Property. Assets sold during the year ended December 31, 2006 generated a net gain of $2.1 million as compared to a gain of $8.1 million during the year ended December 31, 2005. The gains in 2006 and 2005 primarily related to the sale of inactive gas processing facilities acquired as part of the south Louisiana processing assets and as part of the LIG acquisition.

Depreciation and Amortization. Depreciation and amortization expenses were $82.7 million for the year ended December 31, 2006 compared to $36.0 million for the year ended December 31, 2005, an increase of $46.7 million, or 130%. An increase of $38.3 million in depreciation expense was associated with the acquisition of Midstream assets in 2005 and 2006 . The acquisition of the Treating assets and the increase in existing Treating assets in service contributed an increase of $5.0 million. The remaining increase of $3.4 million was a result of various other expansion projects, including the expansion of our corporate offices and related support facilities.

Interest Expense. Interest expense was $51.4 million for the year ended December 31, 2006 compared to $15.8 million for the year ended December 31, 2005, an increase of $35.7 million. The increase relates primarily to an increase in debt outstanding as a result of acquisitions and other growth projects and higher interest rates between years (weighted average rate of 6.9% in 2006 compared to 6.3% in 2005). Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2006	2005
Senior notes	$ 23.6	$ 8.5
Credit facility	30.1	6.8
Other	4.3	1.7
Capitalized interest	(5.4)	(0.9)
Realized interest rate swap gains	(0.1)	—
Interest income	(1.1)	(0.3)
Total	$ 51.4	$ 15.8

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 natural gas liquids are delivered or at the time the service is performed. We generally accrue one to two months of sales and the related gas purchases and reverse these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

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

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

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

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

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

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

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

- changes in general economic conditions in regions in which our markets are located;

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

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

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

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

Liquidity and Capital Resources

Cash Flows from Operating Activities. Net cash provided by operating activities was $114.8 million, $113.0 million and $14.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. Income before non-cash income and expenses and changes in working capital for 2007, 2006 and 2005 were as follows (in millions):

	Years Ended December 31,		
	2007	2006	2005
Income before non-cash income and expenses	$ 138.9	$ 88.3	$ 62.8
Changes in working capital	(24.0)	24.7	(48.7)

The primary reason for the increased income before non-cash income and expenses of $50.6 million from 2006 to 2007 was increased operating income from our expansion in north Texas during 2006 and 2007. The primary reason for the increased income before non-cash income and expenses of $25.5 million from 2005 to 2006 was increased operating income from our south Louisiana and NTG acquisitions. Our working capital deficit has decreased from December 31, 2006 to December 31, 2007, as discussed under “Working Capital Deficit” below.

Cash Flows from Investing Activities. Net cash used in investing activities was $411.4 million, $885.8 million and $615.0 million for the years ended December 31, 2007, 2006 and 2005, respectively. Our primary investing activities for 2007, 2006 and 2005 were capital expenditures and acquisitions, net of accrued amounts, as follows (in millions):

	Years Ended December 31,		
	2007	2006	2005
Growth capital expenditures	$ 403.7	$ 308.8	$ 115.5
Acquisitions and asset purchases	—	576.1	505.5
Maintenance capital expenditures	10.8	6.0	5.0
Total	$ 414.5	$ 890.9	$ 626.0

Net cash invested in Midstream assets was $385.8 million for 2007, $746.7 million for 2006 (including $475.4 million related to the acquisition of assets from Chief) and $583.5 million for 2005 (including $489.4 million related to the acquisition of south Louisiana assets from El Paso). Net cash invested in Treating assets was $23.5 million for 2007, $86.8 million for 2006 (including $51.5 million related to the acquisition of Hanover assets) and $35.9 million for 2005 (including $9.3 million related to the acquisition of Graco assets and $6.7 million related to the acquisition of Cardinal assets).

Cash flows from investing activities for the years ended December 31, 2007, 2006 and 2005 also include proceeds from property sales of $3.1 million, $5.1 million and $11.0 million, respectively. These sales primarily related to sales of inactive properties.

Cash Flows from Financing Activities. Net cash provided by financing activities was $295.9 million, $772.2 million and $596.6 million for the years ended December 31, 2007, 2006 and 2005, respectively. Our financing activities primarily relate to funding of capital expenditures and acquisitions. Our financings have primarily consisted of borrowings under our bank credit facility, equity offerings and senior note issuances for 2007, 2006 and 2005 as follows (in millions):

	Years Ended December 31,		
	2007	2006	2005
Net borrowings under bank credit facility	$ 246.0	$ 166.0	$ 289.0
Senior note issuances (net of repayments)	(9.4)	298.5	85.0
Common unit offerings(1)	58.8	—	273.3
Senior subordinated unit offerings(1)	102.6	368.3	51.1

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

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

	Years Ended December 31,		
	2007	2006	2005
Common units	$ 49.8	$ 39.7	$ 16.5
Subordinated units	11.9	16.1	17.4
General partner	24.8	20.4	9.4
Total	$ 86.5	$ 76.2	$ 43.3

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 2007, 2006 and 2005 were as follows (in millions):

	Years Ended December 31,		
	2007	2006	2005
Increase (decrease) in drafts payable	$ (19.0)	$ 18.1	$ (8.8)

Working Capital Deficit. We had a working capital deficit of $46.9 million as of December 31, 2007, primarily due to drafts payable of $28.9 million as of the same date. As discussed under "Cash Flows" above, in order to reduce our interest costs we do not borrow money to fund outstanding checks until they are presented to our bank. We borrow money under our $1.185 billion credit facility to fund checks as they are presented. As of December 31, 2007, we had approximately $323.7 million of available borrowing capacity under this facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2007 and 2006.

December 2007 Sale of Common Units. On December 19, 2007, we issued 1,800,000 common units representing limited partner interests in the Partnership at a price of $33.28 per unit for net proceeds of

$57.6 million. In addition, Crosstex Energy GP, L.P. made a general partner contribution of $1.2 million in connection with the issuance to maintain its 2% general partner interest.

March 2007 Sale of Senior Subordinated Series D Units. On March 23, 2007, we issued an aggregate of 3,875,340 senior subordinated series D units representing limited partner interests in a private offering for net proceeds of approximately $99.9 million. The senior subordinated series D units were issued at $25.80 per unit, which represented a discount of approximately 25% to the market value of common units on such date. The discount represented an underwriting discount plus the fact that the units will 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 will automatically convert into common units on March 23, 2009 at a ratio of one common unit for each senior subordinated series D unit, subject to adjustment depending on the achievement of financial metrics in the fourth quarter of 2008. The senior subordinated series D units are not entitled to distributions of available cash or allocations of net income/loss from us until March 23, 2009.

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

November 2005 Sale of Senior Subordinated B Units. On November 1, 2005, we issued 2,850,165 senior subordinated series B units in a private placement for a purchase price of $36.84 per unit. We received net proceeds of approximately $107.1 million, including Crosstex Energy GP, L.P.'s general partner contribution of $2.1 million and expenses associated with the sale. The senior subordinated series B units automatically converted into common units on November 14, 2005 at a ratio of one common unit for each senior subordinated series B unit and were not entitled to distributions paid on November 14, 2005.

November 2005 Public Offering. In November 2005, we issued 3,731,050 common units to the public at a purchase price of $33.25 per unit. The offering resulted in net proceeds to the Partnership of $120.9 million, including Crosstex Energy GP, L.P.'s general partner contribution of $2.5 million and net of expenses associated with the offering.

June 2005 Sale of Senior Subordinated Units. In June 2005, we issued 1,495,410 senior subordinated units in a private equity offering for net proceeds of $51.1 million, including Crosstex Energy GP, L.P.'s general partner contribution of $1.1 million. These units automatically converted to common units on a one-for-one basis on February 24, 2006. The senior subordinated units received no distributions until their conversion to common units in February 2006.

Capital Requirements. The natural gas gathering, transmission, treating and processing businesses are capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to be:

- growth capital expenditures such as those to acquire additional assets to grow our business, to expand and upgrade gathering systems, transmission capacity, processing plants or treating plants, and to construct or acquire new pipelines, processing plants or treating plants, and expenditures made in support of that growth; and
- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain existing operating capacity of our assets and to extend their useful lives, or other capital expenditures which do not increase the partnership's cash flows.

Given our objective of growth through large capital expansions and acquisitions, we anticipate that we will continue to invest significant amounts of capital to grow and to build and acquire assets. We actively consider a variety of assets for potential development or acquisition. We are continuing our build-out of our north Texas facilities during 2008, including a 29-mile natural gas gathering pipeline in north Johnson County, Texas, which is under construction and scheduled to be completed in the second quarter of 2008.

We believe that cash generated from operations will be sufficient to meet our present quarterly distribution level of $0.61 per unit and to fund a portion of our anticipated capital expenditures through December 31, 2008. Total capital expenditures are budgeted to be approximately $250 million in 2008, including approximately $23 million for maintenance capital expenditures. In 2008, it is possible that not all of the planned projects will be commenced or completed. We expect to fund our maintenance capital expenditures from operating cash flows. We expect to fund the growth capital expenditures from the proceeds of borrowings under the bank credit facility discussed below, and from other debt and equity sources. Our ability to pay distributions to our unit holders and to fund planned capital expenditures and to make acquisitions will depend upon our future operating performance, which will be affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2007, is as follows:

	Payments due by Period						
	Total	2008	2009	2010 (In millions)	2011	2012	Thereafter
Long-Term Debt	$ 1,223.1	$ 9.4	$ 9.4	$ 20.3	$ 766.0	$ 93.0	$ 325.0
Interest Payable on Fixed Long-Term Debt Obligations	196.4	32.8	32.1	31.0	29.8	26.3	44.4
Capital Lease Obligations	4.7	0.4	0.4	0.4	0.4	0.4	2.7
Operating Leases	104.9	24.7	21.4	18.4	17.3	16.3	6.8
Unconditional Purchase Obligations	25.7	25.7	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—	—
Total Contractual Obligations	$ 1,554.8	$ 93.0	$ 63.3	$ 70.1	$ 813.5	$ 136.0	$ 378.9

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

The Partnership’s interest payable under its Credit Facility is not reflected in the above table because such amounts depend on outstanding balances and interest rates which will vary from time to time. Based on balances outstanding and rates in effect at December 31, 2007, annual interest payments would be $49.8 million. The interest amounts also exclude estimates of the effect of our interest rate swap contracts.

The unconditional purchase obligations for 2008 relate to purchase commitments for equipment. We have also committed to contract for 150,000 MMBtu/d of firm transportation capacity on a pipeline that is expected to be in service in the fourth quarter of 2008. This commitment is not reflected in the summary above since the pipeline is not yet constructed. Under the transportation commitment agreement with Boardwalk Pipeline Partners, L.P., we will be obligated to issue an $80.0 million letter of credit if demanded by Boardwalk prior to the commencement of operation of this new pipeline.

Description of Indebtedness

As of December 31, 2007 and 2006, long-term debt consisted of the following (in thousands):

	2007	2006
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2007 and 2006 were 6.71% and 7.20%, respectively	$ 734,000	$ 488,000
Senior secured notes, weighted average interest rates at December 31, 2007 and 2006 of 6.75% and 6.76%, respectively	489,118	498,530
Note payable to Florida Gas Transmission Company	—	600
	1,223,118	987,130
Less current portion	(9,412)	(10,012)
Debt classified as long-term	$ 1,213,706	$ 977,118

Credit Facility. In September 2007, we increased borrowing capacity under the bank credit facility to $1.185 billion. The bank credit facility matures in June 2011. As of December 31, 2007, $861.3 million was outstanding under the bank credit facility, including $127.3 million of letters of credit, leaving approximately $323.7 million available for future borrowing.

Obligations under the bank credit facility are secured by first priority liens on all of our material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of our equity interests in certain of our subsidiaries, and rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by certain of our subsidiaries. We may prepay all loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

Under the amended credit agreement, borrowings bear interest at our option at the administrative agent's reference rate plus 0% to 0.25% or LIBOR plus 1.00% to 1.75%. The applicable margin varies quarterly based on our leverage ratio. The fees charged for letters of credit range from 1.00% to 1.75% per annum, plus a fronting fee of 0.125% per annum. We will incur quarterly commitment fees ranging from 0.20% to 0.375% on the unused amount of the credit facilities.

The credit agreement prohibits us from declaring distributions to unit-holders if any event of default, as defined in the credit agreement, exists or would result from the declaration of distributions. In addition, the bank credit facility contains various covenants that, among other restrictions, limit our ability to:

- incur indebtedness;
- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make distributions;
- change the nature of its business;
- enter into certain commodity contracts;
- make certain amendments to our or the operating partnership's partnership agreement; and
- engage in transactions with affiliates.

In April 2007, we amended our bank credit facility, effective as of March 28, 2007, to increase the maximum permitted leverage ratio for the fiscal quarter ending September 30, 2007 and each fiscal quarter thereafter. The maximum leverage ratio (total funded debt to consolidated pro forma earnings before interest, taxes, depreciation and amortization) is as follows (provided, however, that during an acquisition period as defined in the bank credit facility, the maximum leverage ratio shall be increased by 0.50 to 1.00 from the otherwise applicable ratio set forth below):

- 5.25 to 1.00 for fiscal quarters through December 31, 2007;
- 5.00 to 1.00 for any fiscal quarter ending March 31, 2008 through September 2008;
- 4.75 to 1.00 for fiscal quarters ending December 31, 2008 and March 31, 2009; and
- 4.50 to 1.00 for any fiscal quarter ending thereafter.

Additionally, the bank credit facility now provides that (i) if we or our subsidiaries incur unsecured note indebtedness, the leverage ratio will shift to a two-tiered structure and (ii) during periods where we have outstanding unsecured note indebtedness, our leverage ratio cannot exceed 5.50 to 1.00 and our senior leverage ratio cannot exceed 4.50 to 1.00. The other material terms and conditions of the credit facility remained unchanged.

The bank credit facility contains a covenant requiring us to maintain a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, equal to 3.0 to 1.0.

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

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

We are subject to interest rate risk on our credit facility and have entered into interest rate swaps to reduce this risk. See Note (5) to the financial statements for a discussion of interest rate swaps.

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

Month Issued	Amount	Interest Rate	Maturity	Principal Payment Terms
June 2003	$ 30,000	6.95%	7 years	Quarterly payments of $1,765 from June 2006-June 2010
July 2003	10,000	6.88%	7 years	Quarterly payments of $588 from July 2006-July 2010
June 2004	75,000	6.96%	10 years	Annual payments of $15,000 from July 2010-July 2014
November 2005	85,000	6.23%	10 years	Annual payments of $17,000 from November 2010-December 2014
March 2006	60,000	6.32%	10 years	Annual payments of $12,000 from March 2012-March 2016
July 2006	245,000	6.96%	10 years	Annual payments of $49,000 from July 2012-July 2016
Total Issued	505,000			
Principal repaid	(15,882)			
Balance as of December 31, 2007	$ 489,118			

In April 2007, we amended the senior note agreement, effective as of March 30, 2007, to (i) provide that if our leverage ratio at the end of any fiscal quarter exceeds certain limitations, we will pay the holders of the senior secured notes an excess leverage fee based on the daily average outstanding principal balance of the senior secured notes during such fiscal quarter multiplied by certain percentages set forth in the senior note agreement; (ii) increase the rate of interest on each senior secured note by 0.25% if, at any given time during an acquisition period (as defined in the senior note agreement), the leverage ratio exceeds 5.25 to 1.00; (iii) cause the leverage ratio to shift to a two-tiered structure if we or our subsidiaries incur unsecured note indebtedness; and (iv) limit our leverage ratio to 5.25 to 1.00 and our senior leverage ratio to 4.25 to 1.00 during periods where we have outstanding unsecured note indebtedness. The other material items and conditions of the senior note agreement remained unchanged.

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

The $40.0 million of senior secured notes issued in 2003 are redeemable, at our option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the master shelf agreement. The senior secured notes issued 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance. During 2008 the notes may also incur an additional fee each quarter of 0.15% per annum on the outstanding borrowings if our leverage ratio, as defined in the agreement, exceeds certain levels during such quarterly period.

The master shelf agreement relating to the notes contains substantially the same covenants and events of default as the bank credit facility.

We were in compliance with all debt covenants at December 31, 2007 and 2006 and expect to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement, the lenders under the bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by us and our subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under the bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under the bank credit facility and the master shelf agreement.

Credit Risk

We are diligent in attempting to ensure that we issue credit to only credit-worthy customers. However, our purchase and resale of gas and NGLs 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.

Inflation

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

Environmental

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

Contingencies

On November 15, 2007, Crosstex CCNG received a demand letter from Denbury asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. The claim arises from a contract under which Crosstex CCNG processed natural gas owned or controlled by Denbury in north Texas. Denbury contends that Crosstex CCNG breached the contract by failing to build a processing plant of a certain size and design, resulting in Crosstex CCNG's failure to properly process the gas over a ten month period. Denbury also alleges that Crosstex CCNG failed to provide specific notices required under the contract. On December 4, 2007 and again on February 14, 2008, Denbury sent Crosstex CCNG letters demanding that its claim be arbitrated pursuant to an arbitration provision in the contract. Denbury subsequently requested that the parties attempt to mediate the matter before any arbitration proceeding is initiated. Although it is not possible to predict with certainty the ultimate outcome of this matter, we do not believe this will have a material adverse effect on our consolidated results of operations or financial position.

Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), *"Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109,"* which the Partnership adopted effective January 1, 2007. FIN 48 addressed the determination of how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The adoption of FIN 48 had no material impact to our financial statements. At December 31, 2007, we have no material assets, liabilities or accrued interest and penalties associated with uncertain tax positions. 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, 2007, tax years 2004 through 2007 remain subject to examination by the Internal Revenue Service and applicable states. We do not expect any material changes in the balance of our unrecognized tax benefit over the next twelve months.

On September 13, 2006, the Securities Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (SAB 108), which establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the company's financial statements and the related disclosures. SAB 108 requires the use of a balance sheet and an income statement approach to evaluate whether either of these approaches results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. We adopted SAB 108 effective October 1, 2006 with no material impact on its financial statements.

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, *"Fair Value Measurements"* (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. While SFAS 157 does not add any new fair value measurements, it is intended to increase consistency and comparability of such measurement. The provisions of SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The adoption of this standard will not have a material impact on our results of operations, financial position or cash flows.

In February 2007, the FASB issued SFAS No. 159, *"Fair Value Option for Financial Assets and Financial Liabilities-Including an amendment to FASB Statement No. 115"* (SFAS 159) permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. The adoption of SFAS 159 will have no material impact on our financial statements.

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

Disclosure Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, that are based on information currently available to management as well as management's assumptions and beliefs. All statements, other than statements of historical fact, included in this Form 10-K constitute forward-looking statements, including but not limited to statements identified by the words "may," "will," "should," "plan," "predict," "anticipate," "believe," "intend," "estimate" and "expect" and similar expressions. Such statements reflect our current views with respect to future events, based on what we believe are reasonable assumptions; however, such statements are subject to certain risks and uncertainties. In addition to the specific uncertainties discussed elsewhere in this Form 10-K, the risk factors set forth in "Item 1A. Risk Factors" may affect our performance and results of operations. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may differ materially from those in the forward-looking statements. We disclaim any intention or obligation to update or review any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

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

Interest Rate Risk

We are exposed to interest rate risk on our variable rate bank credit facility. At December 31, 2007 and 2006, our bank credit facility had outstanding borrowings of $734.0 million and $488.6 million, respectively, which approximated fair value. We manage a portion of our interest rate exposure on our variable rate debt by utilizing interest rate swaps, which allow us to convert a portion of variable rate debt into fixed rate debt. We entered into interest rate swaps in 2007 covering $450.0 million of the variable rate debt for a period of three years at interest rates ranging from 4.7% to 5.07% (coverage periods end from November 2009 through October 2010). As of December 31, 2007, the fair value of these interest rate swaps was reflected as a liability of $11.3 million ($3.2 million in current liabilities and $8.1 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 $10.3 million. Considering the interest rate swaps and the amount outstanding on our bank credit facility as of December 31, 2007, we estimate that a 1% increase or decrease in the interest rate would change our annual interest expense by approximately $2.8 million for periods when the entire portion of the $450.0 million of interest rate swaps are outstanding and $7.3 million for annual periods after 2010 when all the interest rate swaps lapse.

At December 31, 2007 and 2006, we had total fixed rate debt obligations of $489.1 million and $498.5 million, respectively, consisting of our senior secured notes with a weighted average interest rate of 6.75%. The fair value of these fixed rate obligations was approximately $500.5 million and $503.9 million as of December 31, 2007 and 2006, respectively. We estimate that a 1% increase or decrease in interest rates would increase or decrease the fair value of the fixed rated debt (our senior secured notes) by $11.4 million based on the debt obligations as of December 31, 2007.

Commodity Price Risk

Approximately 4.3% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. 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. As of December 31, 2007, we have hedged approximately 95% of our exposure to natural gas price fluctuations through December 2008 and approximately 34% of our exposure to natural gas price fluctuations for 2009.

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

We also have hedges in place covering liquids volumes we expect to receive under percent of proceeds contracts. At our south Louisiana plants, we have hedged approximately 80% of our exposure through May 2008 and at various levels less than 50% from June 2008 through the first quarter of 2009. For our other assets, we have hedged approximately 69% of our exposure through June 2008 and at various levels less than 50% from July 2008 through the first quarter of 2009.

We have commodity price risk associated with our processed volumes of natural gas. We currently process gas under four main types of contractual arrangements:

1. Keep-whole contracts: Under this type of contract, we pay the producer for the full amount of inlet gas to the plant, and we make a margin based on the difference between the value of liquids recovered from the processed natural gas as compared to the value of the natural gas volumes lost ("shrink") in processing. Our margins from these contracts are high during periods of high liquids prices relative to natural gas prices, and can be negative during periods of high natural gas prices relative to liquids prices. We control our risk on our current keep-whole contracts primarily through our ability to bypass processing when it is not profitable for us.

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

3. Theoretical processing contracts: Under these contracts, we stipulate with the producer the assumptions under which we will assume processing economics for settlement purposes, independent of actual processing results or whether the stream was actually processed. These contracts tend to have an inverse result to the keep-whole contracts, with better margins as processing economics worsen.

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

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 NYMEX futures or 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, 2007, 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 $9.3 million. The aggregate effect of a hypothetical 10% increase in gas and NGLs prices would result in an increase of approximately $5.9 million in the net fair value liability of these contracts as of December 31, 2007.

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-44 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, 2007 in alerting them in a timely manner to material information required to be disclosed in our reports filed with the Securities and Exchange Commission.

(b) Changes in Internal Control Over Financial Reporting

There has been no change in our internal controls over financial reporting that occurred in the three months ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

Internal Control Over Financial Reporting

See “Management’s Report on Internal Control over Financial Reporting” on page F-2.

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

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	46	President, Chief Executive Officer and Director
Robert S. Purgason	51	Executive Vice President — Chief Operating Officer
Jack M. Lafield	57	Executive Vice President — Corporate Development
William W. Davis	54	Executive Vice President and Chief Financial Officer
Joe A. Davis	47	Executive Vice President, General Counsel and Secretary
Rhys J. Best**	61	Director and Member of the Conflicts Committee and Compensation Committee*
James C. Crain **	59	Director and Member of the Audit Committee* and Governance Committee
Leldon E. Echols**	52	Director and Member of the Audit Committee
Bryan H. Lawrence	65	Chairman of the Board
Sheldon B. Lubar **	78	Director and Member of the Governance Committee*
Cecil E. Martin **	66	Director and Member of the Audit Committee and Compensation Committee
Robert F. Murchison **	54	Director and Member of the Compensation Committee and Governance Committee
Kyle D. Vann **	60	Director and Member of the Conflicts Committee* and Compensation 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 was President and Chief Operating Officer of Comstock Natural Gas and founder of Ventana Natural Gas, a gas marketing and pipeline company that was purchased by Comstock Natural Gas. Mr. Davis started Ventana Natural Gas in June 1992. Prior to starting Ventana, he was Vice President of Marketing and Project Development for Endevco, Inc. Before joining Endevco, Mr. Davis was employed by Enserch Exploration in the marketing group. Mr. Davis also serves as a director of Crosstex Energy, Inc. Mr. Davis holds a B.B.A. in Finance from Texas Christian University.

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

Jack M. Lafield, Executive Vice President — Corporate Development, joined our predecessor in August 2000. For five years prior to joining Crosstex, Mr. Lafield was Managing Director of Avia Energy, an energy consulting group, and was involved in all phases of acquiring, building, owning and operating midstream assets and natural gas reserves. He also provided project development and consulting in domestic and international energy projects to major industry and financing organizations, including development, engineering, financing, implementation and operations. Prior to consulting, Mr. Lafield held positions of President and Chief Executive Officer of Triumph Natural Gas, Inc., a private midstream business he founded, President and Chief Operating Officer of Nagasco, Inc. (a joint venture with Apache Corporation), President of Producers' Gas Company, and Senior Vice President of Lear Petroleum Corp. Mr. Lafield holds a B.S. degree in Chemical Engineering from Texas A&M University, and is a graduate of the Executive Program at Stanford University.

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

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

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

James C. Crain joined Crosstex Energy GP, LLC as a director in December 2005. Since 1989, Mr. Crain has served as president of Marsh Operating Company, where he has worked since 1984, an investment management company focusing on energy investing, and since 1997 as general partner of Valmora Partners, L.P., a private investment partnership. Prior to Marsh, he served as a partner at Jenkens & Gilchrist where he headed the law firm's energy section. Mr. Crain also serves on the boards of GeoMet, Inc., (NASDAQ: GMET), and Approach Resources, Inc. (NASDAQ: AREX). He graduated from the University of Texas at Austin with a B.B.A. degree, a master of professional accounting and a doctor of jurisprudence.

Leldon E. Echols joined Crosstex Energy GP, LLC as a director in January 2008. 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. 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 closing of the recently completed private equity buyout of TXU. Mr. Echols earned a Bachelor of Science degree in accounting from Arkansas State University and is a Certified Public Accountant. He is a member of the American Institute of Certified Public Accountants and the Texas Society of CPAs. Mr. Echols has also served as a director of Crosstex Energy, Inc. since January 2008.

Bryan H. Lawrence, Chairman of the Board, joined Crosstex Energy GP, LLC as a director upon the completion of our initial public offering in December 2002. 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) and Winstar Resources Ltd. (a Canadian public company), Approach Resources, Inc. (NASDAQ: AREX) and certain non-public companies in the energy industry in which Yorktown partnerships hold equity interests. Mr. Lawrence is a graduate of Hamilton College and also has an M.B.A. from Columbia University.

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

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

Robert F. Murchison joined us as a director upon the completion of our initial public offering in December 2002. Mr. Murchison has been the President of the general partner of Murchison Capital Partners, L.P., a private equity investment partnership, since 1992. Prior to founding Murchison Capital Partners, L.P., Mr. Murchison held various positions with Romacorp, Inc., the franchisor and operator of Tony Roma's restaurants, including Chief Executive Officer from 1984 to 1986 and Chairman of the board of directors from 1984 to 1993. He served as a director of Cenergy Corporation, an oil and gas exploration and production company, from 1984 to 1987, Conquest Exploration Company from 1987 to 1991 and has served as a director of TNW Corporation, a short line railroad holding company, since 1981, and Tecon Corporation, a holding company with holdings in real estate development and the fund of funds management business, since 1978. Mr. Murchison has also served as a director of Crosstex Energy, Inc. since January 2004. Mr. Murchison holds a bachelor's degree in history from Yale University.

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

Independent Directors

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

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

Board Committees

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

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

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

Code of Ethics

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

Section 16(a) — Beneficial Ownership Reporting Compliance

Based upon our records, except as set forth below, we believe that during 2007 all reporting persons complied with the Section 16(a) filing requirements applicable to them. Due to administration errors, a Form 4 reporting two transactions was filed late on behalf of Susan McAden on November 13, 2007.

Reimbursement of Expenses of our General Partner and its Affiliates

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

Item 11. *Executive Compensation*

Compensation Discussion and Analysis

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

Based on the information that we track regarding the amount of time spent by each of our named executive officers on business matters relating to Crosstex Energy, L.P., we estimate that such officers devoted the following percentage of their time to the business of Crosstex Energy, L.P. and to Crosstex Energy, Inc., respectively, for 2007:

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	85%	15%
Jack M. Lafield	100%	0%
William W. Davis	77%	23%
Robert S. Purgason	100%	0%
Joe A. Davis	94%	6%

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

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

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

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

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

Compensation Consultant. In 2007, Crosstex Energy GP, LLC's Compensation Committee retained Mercer Human Resource Consulting ("Mercer") as its independent compensation consultant to conduct a compensation study and advise the Compensation Committee on certain matters relating to compensation programs applicable to the named executive officers and other employees of Crosstex Energy GP, LLC. Mercer provided a presentation to the Compensation Committee regarding the compensation programs of the Crosstex entities in February 2007.

With respect to compensation objectives and decisions regarding the named executive officers the Compensation Committee has reviewed market data with respect to peer companies provided by Mercer in determining relevant compensation levels and compensation program elements for our named executive officers, including establishing base salaries, for fiscal 2007. Mercer has provided guidance on current industry best practices to the Compensation Committee. The market data that we reviewed included the base salaries paid to executive officers in similar positions at our peer companies, as well as a comparison of the mix of total compensation (including base salary, bonus structure, bonus methodology and short and long-term compensation elements) paid to executive officers in similar positions at such companies. For 2007, our peer companies consisted of the following: Energy Transfer Partners, L.P., Enbridge Energy Partners, L.P., ONEOK Partners, L.P., Southern Union, Magellan

Midstream Holdings, L.P., Valero, L.P., Copano Energy, LLC, Regency Energy Partners, L.P., MarkWest Energy Partners, L.P., Boardwalk Pipeline Partners, L.P., Atmos Energy Corporation, El Paso Corporation, Questar Corporation, Equitable Resources, Inc., Pioneer Natural Resources Company, Plains Exploration & Production Company, Cabot Oil & Gas Corporation, St. Mary Land & Exploration Company and Range Resources Corporation. We believe that this group of companies is representative of the industry in which we operate and the individual companies were chosen because of such companies' relative position in our industry, their relative size/market capitalization, the relative complexity of the business, similar organizational structure and the named executive officers' roles and responsibilities.

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

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 2007, the principal elements of compensation for the named executive officers were the following:

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

Base Salary. Crosstex Energy GP, LLC's Compensation Committee establishes base salaries for the named executive officers based on the historical salaries for services rendered to Crosstex Energy GP, LLC and its affiliates, market data and responsibilities of the named executive officers. Salaries are generally determined by considering the employee's performance and prevailing levels of compensation in areas in which a particular employee works. As discussed above, except with respect to the monthly reimbursement payment received from Crosstex Energy, Inc., all of the base salaries of the named executive officers were allocated to us by Crosstex Energy GP, LLC as general and administration expenses. The base salaries paid to our named executive officers during fiscal year 2007 are shown in the Summary Compensation Table on page 69.

Each of the named executive officers, including Barry E. Davis, Jack M. Lafield, William W. Davis, Robert S. Purgason and Joe A. Davis have entered into employment agreements with Crosstex Energy GP, LLC. All of these employment agreements are substantially similar, with certain exceptions as set forth below. Each of the employment agreements has a term of one year that will automatically be extended such that the remaining term of the agreements will not be less than one year. The employment agreements provide for a base annual salary of $400,000, $290,000, $290,000, $290,000, and $265,000 for Barry E. Davis, Jack M. Lafield, William W. Davis, Robert S. Purgason and Joe A. Davis, respectively, as of January 1, 2008.

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

Annual Cash Bonus Plan Awards. Crosstex Energy GP, LLC's Compensation Committee awarded cash bonus awards to each of the named executive officers in 2007. Crosstex uses financial and operational goals, as well as individual performance goals, to determine the amount of cash bonus awards that we pay to our named executive officers. Bonuses are generally based on return on invested capital ("ROI"), bottom-line profitability, customer satisfaction, overall company growth, corporate governance, adherence to policies and procedures and other factors that vary depending on an employee's responsibilities. Approximately two-thirds of the bonuses payable to our named executive officers for fiscal 2007 were based upon a formula that is tied to ROI achieved by us during the year. If a predetermined ROI is accomplished, then the bonus is paid and is increased or decreased based on the ROI percentage that is achieved, with minimum payouts of 10%, target payouts ranging from 40% to 90%, and maximum payouts ranging from 80% to 180% of an executive officer's base salary. Target ROI is based upon a standard of reasonable market expectations and company performance, and varies from year to year within a range of 10% to 20% (with any variation within this range not being material to an understanding of the arrangement). Several factors are reviewed in determining target ROI, including market expectations, internal forecasts and available investment opportunities. We exceeded the target ROI for 2007 resulting in our named executive officers receiving a 130% of target payout for this portion of their bonuses.

The remaining one-third of the bonuses payable to our named executive officers for fiscal 2007 were determined, in the discretion of the Compensation Committee, based upon the Compensation Committee's assessment of performance objectives. These performance objectives include the quality of leadership within the named executive officer's assigned area of responsibility, the achievement of technical and professional proficiencies by the named executive officer, the execution of identified priority objectives by the named executive officer and the named executive officer's contribution to, and enhancement of, the desired company culture. These performance objectives are reviewed and evaluated by our Compensation Committee as a whole. All of our named executive officers met or exceeded their personal performance objectives for 2007.

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

Crosstex Energy GP, LLC Long-Term Incentive Plan. Crosstex Energy GP, LLC has adopted a long-term incentive plan for employees and directors of Crosstex Energy GP, LLC and its affiliates who perform services for us. The long-term incentive plan is administered by Crosstex Energy GP, LLC's Compensation Committee and permits the grant of awards covering an aggregate of 4,800,000 common units, which may be awarded in the form of restricted units or unit options. Of the 4,800,000 common units that may be awarded under the long-term incentive plan, 2,567,340 common units remain eligible for future grants by Crosstex Energy GP, LLC as of January 1, 2008. The long-term compensation structure is intended to align the employee's performance with long-term performance for our unitholders.

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

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

- *Restricted Units.* A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit. In the future, the Compensation Committee may make grants under the plan to employees and directors containing such terms as it shall determine under the plan. The Compensation Committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted units will vest upon a change of control of us or of our general partner, as discussed below under "— Potential Payments Upon a Change of Control or Termination." Common units to be delivered upon the vesting of restricted units may be common units acquired by Crosstex Energy GP, LLC in the open market, common units already owned by Crosstex Energy GP, LLC, common units acquired by Crosstex Energy GP, LLC directly from us or any other person or any combination of the foregoing. Crosstex Energy GP, LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units, the total number of common units outstanding will increase. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights with respect to restricted units which entitles the grantee to distributions attributable to the restricted units prior to vesting of such units. We intend the issuance of the common units upon vesting of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, under current policy, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.
- *Performance Units.* A performance unit represents a contractual commitment to grant restricted units in the future if certain conditions are satisfied. It is contemplated that performance unit agreements will only be entered into with members of our senior management. Under the terms of the performance unit agreements, to be eligible to receive the restricted units, the executive officer must continuously be employed from the date of the agreement through January 1 of the third calendar year following such date, and no units will be credited to an award recipient under our long term incentive plan until such future date. Each agreement provides for a target number of units that are to be granted in the future. The target number of units will be increased (up to a maximum of 200% of the target number of units) or decreased (to a minimum of 30% of the target number of units) based on Crosstex Energy, L.P.'s average growth rate (defined as the percentage increase or decrease in distributable cash flow per unit) compared to the target growth rate established in the applicable performance unit agreement which will vary from year to year. In 2007, the target growth rate was 10.5%. Generally, the restricted units that are granted pursuant to a performance unit agreement will vest and become unrestricted as of March 1 of the year of grant if the executive officer remains an employee through such date.

On an aggregate basis, in the past the Crosstex entities generally have granted equity compensation in a amount of up to 300% of the chief executive officer's base salary and up to 200% of each other named executive officer's base salary. The total value of the equity compensation granted to our named executive officers generally has been allocated 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. For fiscal year 2007, Crosstex Energy GP, LLC granted 16,081, 7,773, 7,773, 7,773 and 5,327 performance units to Barry E. Davis, Jack M. Lafield, William W. Davis, Robert S. Purgason and Joe A. Davis, respectively. All performance and restricted units that we grant are charged against earnings according to SFAS No. 123R.

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

The Crosstex Energy, Inc. long-term incentive plan provides for the award of stock options and restricted stock (collectively, "Awards") for up to 4,590,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2008, approximately 924,533 shares remained available under the long-term incentive plan for future issuance to participants. A participant may not receive in any calendar year options relating to more than 100,000 shares of common stock. The maximum number of shares set forth above are subject to appropriate adjustment in the event of a recapitalization of the capital structure of Crosstex Energy, Inc. or reorganization of Crosstex Energy, Inc. Shares of common stock underlying Awards that are forfeited, terminated or expire unexercised become immediately available for additional Awards under the long-term incentive plan.

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

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

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

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

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

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

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

As discussed above, on an aggregate basis, in the past the Crosstex entities generally have granted equity compensation in a amount of up to 300% of the chief executive officer's base salary and up to 200% of each other named executive officer's base salary. The total value of the equity compensation granted to our executive officers generally has been awarded 50% in restricted units of Crosstex Energy, L.P. and 50% in restricted stock of Crosstex Energy, Inc. In addition, our executive officers may receive additional grants of equity compensation in certain circumstances, such as promotions. For fiscal year 2007, Crosstex Energy, Inc. granted 18,750, 8,976, 8,976, 8,976 and 6,151 performance shares to Barry E. Davis, Jack M. Lafield, William W. Davis, Robert S. Purgason and Joe A. Davis, respectively. All performance and restricted shares that we grant are charged against earnings according to SFAS No. 123R.

Retirement and Health Benefits. Crosstex Energy GP, LLC offers a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are generally eligible for the same programs on the same basis as other employees of Crosstex Energy GP, LLC. Crosstex Energy GP, LLC maintains a tax-qualified 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax advantages basis. In 2007, Crosstex Energy GP, LLC matched 60% of every dollar contributed for contributions of up to 5% 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 a private lunch club (totaling less than $2,500 per year per person).

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

Potential Payments Upon a Change of Control or Termination.

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

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

If a termination of a named executive officer by Crosstex Energy GP, LLC other than for cause, a termination by a named executive officer for good reason or upon a change in control were to have occurred as of December 31, 2007, our named executive officers would have been entitled to the following:

- Barry E. Davis would have received $400,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $400,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;
- Robert S. Purgason would have received $290,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $226,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;
- Jack M. Lafield would have received $290,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $226,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement;
- William W. Davis would have received $290,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $226,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement; and
- Joe A. Davis would have received $265,000 representing base salary for the remainder of the term of the employment agreement (i.e., one year's salary paid at regularly scheduled times), $226,000 representing bonuses earned under any incentive plans in which he is a participant earned up to the date of termination or change in control and continued participation in Crosstex Energy GP, LLC's health plans for the remainder of the term of the employment agreement.

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

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

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

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

If a change in control were to have occurred as of December 31, 2007, 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 40,524 restricted units and 16,081 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Robert S. Purgason held 23,172 restricted units, 7,773 performance units and options to purchase 10,000 common units that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Jack M. Lafield held 42,859 restricted units and 7,773 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control; and
- William W. Davis held 42,859 restricted units and 7,773 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control.
- Joe A. Davis held 29,699 restricted units and 5,327 performance units that would have become fully vested, payable and/or exercisable as a result of such change in control;

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

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

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

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

If a change in control were to have occurred as of December 31, 2007, options and restricted stock held by the named executive officers would have automatically vested and become payable or exercisable, and any vesting periods of restricted stock would have terminated, as follows:

- Barry E. Davis held 75,654 shares of restricted stock and 18,750 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Robert S. Purgason held 48,630 shares of restricted stock, 8,976 performance shares and options to purchase 30,000 common shares that would have become fully vested, payable and/or exercisable as a result of such change in control;
- Jack M. Lafield held 107,844 shares of restricted stock and 8,976 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control;
- William W. Davis 107,844 shares of restricted stock and 8,976 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control; and
- Joe A. Davis held 53,565 shares of restricted stock and 6,151 performance shares that would have become fully vested, payable and/or exercisable as a result of such change in control.

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

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

Summary Compensation Table

The following table sets forth certain compensation information for our chief executive officer and our four other most highly compensated executive officers in 2007.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(6)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Barry E. Davis	2007	400,000	400,000	1,111,409	—	—	—	213,210(1)	2,124,619
President and Chief Executive Officer	2006	390,000	95,000	1,126,875				167,630(1)	1,779,505
Robert S. Purgason	2007	290,000	226,000	534,691	—	—	—	175,038(2)	1,225,729
Executive Vice President and Chief Operating Officer	2006	222,385	47,500	1,392,025				113,267(2)	1,775,177
Jack M. Lafield	2007	290,000	226,000	534,691	—	—	—	222,622(3)	1,273,313
Executive Vice President	2006	275,000	60,000	685,926				198,061(3)	1,218,987
William W. Davis	2007	290,000	226,000	534,691	—	—	—	227,411(4)	1,278,102
Executive Vice President and Chief Financial Officer	2006	275,000	60,000	685,926				198,061(4)	1,218,987
Joe A. Davis	2007	265,000	226,000	366,422	—	—	—	137,440(5)	994,862
Executive Vice President and General Counsel	2006	250,000	47,500	549,967				86,349(5)	933,816

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

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

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

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

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

(6) The amounts shown represent the amount recognized for financial statement reporting purposes computed in accordance with Statement of Financial Accounting Standards No. 123R, "*Share-Based Payment"*.

Grants of Plan-Based Awards for Fiscal Year 2007 Table

The following tables provide information concerning each grant of an award made to a named executive officer for fiscal year 2007, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plan.

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

		Estimated Future Payouts under Non-Equity Incentive Plan Awards			Estimated Future Payouts under Equity Incentive Plan Awards(1)			All Other Unit Awards: Number of Restricted Units	All Other Unit Awards: Number of Securities Underlying Options
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold ($)	Target ($)	Maximum ($)	(#)	(#)
Barry E. Davis	07/02/07	—	—	—	149,650	498,833	997,665	—	—
Robert S. Purgason	07/02/07	—	—	—	72,336	241,118	482,237	—	—
Jack M. Lafield	07/02/07	—	—	—	72,336	241,118	482,237	—	—
William W. Davis	07/02/07	—	—	—	72,336	241,118	482,237	—	—
Joe A. Davis	07/02/07	—	—	—	49,573	165,244	330,487	—	—

(1) The closing price for the common units was $31.02 as of December 31, 2007.

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

		Estimated Future Payouts under Non-Equity Incentive Plan Awards			Estimated Future Payouts under Equity Incentive Plan Awards(1)			All Other Share Awards: Number of Restricted Shares	All Other Share Awards: Number of Securities Underlying Options
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold ($)	Target ($)	Maximum ($)	(#)	(#)
Barry E. Davis	(2)	—	—	—	209,475	698,250	1,396,500	—	—
Robert S. Purgason	07/02/07	—	—	—	100,280	334,266	668,532	—	—
Jack M. Lafield	07/02/07	—	—	—	100,280	334,266	668,532	—	—
William W. Davis	07/02/07	—	—	—	100,280	334,266	668,532	—	—
Joe A. Davis	07/02/07	—	—	—	68,719	229,063	458,126	—	—

(1) The closing price for the common stock was $37.24 as of December 31, 2007.

(2) Mr. Barry Davis received grants on July 2, 2007 and February 13, 2008 with respect to fiscal year 2007. The February 13, 2008 grant dealt with the omission due to administrative error of 180 performance shares that should have been included in the original grant.

Outstanding Equity Awards at Fiscal Year-End Table

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2007, including, but not limited to, awards made under the Crosstex Energy GP, LLC Long-Term Incentive Plan and the Crosstex Energy, Inc. Long-Term Incentive Plan.

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

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Barry E. Davis	—	—	—	—	—	40,524	1,257,054	16,081	498,833
Robert S. Purgason	10,000	—	—	30.00	11/05/14	23,172	718,795	7,773	241,118
Jack M. Lafield	—	—	—	—	—	42,859	1,329,486	7,773	241,118
William W. Davis	—	—	—	—	—	42,859	1,329,486	7,773	241,118
Joe A. Davis	—	—	—	—	—	29,699	921,263	5,327	165,244

(1) The closing price for the common units was $31.02 as of December 31, 2007.

(2) Performance units reported at target number of units. See discussion on page 62.

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

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)(2)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Barry E. Davis	—	—	—	—	—	75,654	2,817,355	18,750	698,250
Robert S. Purgason	30,000	—	—	13.33	12/07/14	48,630	1,810,981	8,976	334,266
Jack M. Lafield	—	—	—	—	—	107,844	4,016,111	8,976	334,266
William W. Davis	—	—	—	—	—	107,844	4,016,111	8,976	334,266
Joe A. Davis	—	—	—	—	—	53,565	1,994,761	6,151	229,063

(1) The closing price for the common stock was $37.24 as of December 31, 2007.

(2) Performance shares reported at target number of shares. See discussion on page 63.

Option Exercises and Units and Shares Vested Table

The following table provides information related to the exercise of options and vesting of restricted units and restricted shares during fiscal year ended 2007.

OPTION EXERCISES AND UNITS AND SHARES VESTED

	Option Awards		Crosstex Energy, L.P. Unit Awards		Crosstex Energy, Inc. Share Awards	
Name	Number of Units Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
Barry E. Davis	—	—	5,500	198,000	7,500	250,950
Robert S. Purgason	—	—	—	—	15,000	568,350
Jack M. Lafield	—	—	3,500	126,000	11,250	376,425
William W. Davis	—	—	3,500	126,000	11,250	376,425
Joe A. Davis	—	—	—	—	—	—

Compensation of Directors

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash ($)	Unit Awards(1) ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Rhys J. Best	78,000	70,973	—	—	—	6,892	155,865
Frank M. Burke	68,625	70,973	—	—	—	6,892	146,490
James C. Crain	66,750	70,973	—	—	—	6,892	144,615
Leldon E. Echols	—	—	—	—	—	—	—
Bryan H. Lawrence	—	—	—	—	—	—	—
Sheldon B. Lubar	56,626	70,973	—	—	—	6,892	134,491
Cecil E. Martin	65,250	70,973	—	—	—	6,892	143,115
Robert F. Murchison	61,500	70,973	—	—	—	6,892	139,365
Kyle D. Vann	68,167	70,973	—	—	—	6,892	146,032

(1) Each award consists of 2,010 restricted units of Crosstex Energy, L.P. that were granted on May 24, 2007 with a fair market value of $35.31 per unit and that will vest on May 9, 2008.

Each director of Crosstex Energy GP, LLC who is not an employee of Crosstex Energy GP, LLC (except Mr. Lawrence) is paid an annual retainer fee of $50,000. Directors do not receive an attendance fee for each regularly scheduled quarterly board meeting, but are paid $1,500 for each additional meeting that they attend. Also, an attendance fee of $1,500 is paid to each director for each committee meeting he attends. Each committee chairman receives $2,500 annually, except the Audit Committee chairman who receives $7,500 annually. Directors are also reimbursed for related out-of-pocket expenses. Barry E. Davis, as an executive officer of Crosstex Energy GP, LLC, is otherwise compensated for his services and therefore receives no separate compensation for his service as a director. For directors that serve on both the boards of Crosstex Energy GP, LLC and Crosstex Energy, Inc., the above listed fees are generally allocated 75% to us and 25% to Crosstex Energy, Inc. The Governance Committee annually reviews and makes recommendations to the Board of Directors regarding the compensation of the directors.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended 2007, the Compensation Committee was composed of Sheldon B. Lubar, Robert F. Murchison, Kyle Vann, Cecil E. Martin and Rhys J. Best. Mr. Lubar left the committee and Messrs. Vann and Martin joined the committee on May 9, 2007. No member of the Compensation Committee was an officer or employee of Crosstex Energy GP, LLC. None of Crosstex Energy GP, LLC's executive officers served on the board of directors or the compensation committee of any other entity, for which any officers of such other entity served either on Crosstex Energy GP, LLC's Board of Directors or Compensation Committee.

Compensation Committee Report

The Compensation Committee of Crosstex Energy GP, LLC held six meetings during fiscal year 2007. The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with management. Based upon such review, the related discussions and such other matters deemed relevant and appropriate by the Compensation Committee, the Compensation Committee has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Rhys J. Best (Chairman)
Robert F. Murchison
Cecil E. Martin
Kyle D. Vann

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, 2008, 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 41,484,795 common units and 3,875,340 senior subordinated series D units as of February 16, 2008.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Series D Units Beneficially Owned	Percentage of Subordinated Series D Units Beneficially Owned	Total Units Beneficially Owned	Percentage of Total Units Beneficially Owned
Crosstex Energy, Inc.	16,414,830	39.57%			16,414,830	36.19%
Kayne Anderson Capital Advisors, L.P.(2)	4,814,675	11.61%			4,814,675	10.61%
Tortoise Capital Advisors, LLC(3)	3,595,188	8.67%	775,068	20.00%	4,370,256	9.63%
Chieftain Capital Management, Inc.(4)	2,851,030	6.87%			2,851,030	6.29%
Lehman Brothers Holdings Inc.(5)	1,496,790	3.61%	968,835	25.00%	2,465,625	5.44%
The Goldman Sachs Group, Inc.(6)	1,676,601	4.04%			1,676,601	3.70%
Fiduciary Asset Management, L.L.C.(7)	249,470	*	387,534	10.00%	637,004	1.40%
ING Life Insurance & Annuity Company(8)	0	*	705,312	18.20%	705,312	1.55%
Citigroup Global Markets Inc.	0	*	775,068	20.00%	775,068	1.71%
Barry E. Davis(9)	49,167	*			49,167	*
William W. Davis(9)	18,708	*			18,708	*
Robert S. Purgason(9)	12,948	*			12,948	*
Jack M. Lafield(9)	23,647	*			23,647	*
Joe A. Davis(9)	1,000	*			1,000	*
Rhys J. Best	15,000	*			15,000	*
James C. Crain(9)	1,500	*			1,500	*
Leldon E. Echols	0	*			0	*
Bryan H. Lawrence(9)	0	*			0	*
Sheldon B. Lubar(9)(10)	314,922	*			314,922	*
Cecil E. Martin	0	*			0	*
Robert F. Murchison(9)(11)	45,822	*			45,822	*
Kyle D. Vann	9,000	*			9,000	*
All directors & executive officers as a Group (14 persons)	499,141	1.20%	0	0.00%	499,141	1.10%

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Mr. Lawrence, which is 410 Park Avenue, New York, New York 10022; Chieftain Capital Management, FAC, which is 12 East 49th St., New York, New York 10017; Kayne Anderson Capital Advisors, L.P., which is 1800 Avenue of the Stars, Second Floor, Los Angeles, California 90067; Tortoise Capital Advisors LLC, which is 10801 Martin Blvd., Ste 222, Overland Park, Kansas 66210; and Lehman Brothers Holdings, Inc., which is 745 7th Avenue, New York, New York 10019; Goldman Sachs Group, Inc. which is 85 Broad Street, New York, New York 10004; Fiduciary Asset management, LLC which is 8112 Maryland Avenue, Suite 400, St. Louis, Missouri 63105; Life Insurance & Annuity Company which is 5780 Powers Ferry Road NW, Suite 300, Atlanta, Georgia 30327-4349; and Citigroup Global Markets Inc. which is 390 Greenwich Street, 3rdM Floor, New York, New York 10013.

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

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

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

(5) As reported on Schedule 13G filed with the SEC (for common units) and reported jointly with Lehman Brothers MLP opportunity Fund L.P. which holds the Series D units.

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

(7) Owns the common units and reported jointly with Fiduciary/Claymore MLP Opportunity Fund which holds the 387,534 Series D units.

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

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

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

(11) 16,000 units are held by Murchison family trusts. Mr. Murchison and Murchison Capital Partners, L.P. (of which Mr. Murchison is the President of the general partner) hold ownership interests in Crosstex Energy, Inc. as indicated in the following table.

Crosstex Energy, Inc. Ownership

The following table shows the beneficial ownership of Crosstex Energy, Inc. as of February 16, 2007, 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 46,317,703 shares of common stock outstanding as of February 16, 2008.

Name of Beneficial Owner(1)	Shares of Common Stock	Percent
Chieftain Capital Management, Inc.(2)	8,228,733	17.77%
ClearBridge Advisors, LLC(2)	3,226,230	6.97%
Barclays Global Investors, NA(3)	2,917,643	6.30%
Alson Capital Partners, LLC(4)	2,698,723	5.83%
Lubar Nominees(5)	1,966,944	4.25%
Lubar Equity Fund, LLC(5)	468,210	1.01%
Barry E. Davis	1,318,287	2.85%
William W. Davis	146,437	*
Robert S. Purgason(6)	48,986	*
Jack M. Lafield	164,272	*
Joe A. Davis	0	*
James C. Crain(7)	6,000	*
Leldon E. Echols	0	*
Bryan H. Lawrence	1,720,267	3.71%
Sheldon B. Lubar(5)	24,933	*
Cecil E. Martin	0	*
Robert F. Murchison(8)	212,390	*
All directors and executive officers as group (12 persons)		

* Less than 1%.

(1) The address of each person listed above is 2501 Cedar Springs, Suite 100, Dallas, Texas 75201, except for Chieftain Capital Management, Inc., which is 12 East 49th Street, New York, New York 10017; Mr. Lawrence, Yorktown Energy Partners IV, L.P. and Yorktown Energy Partners V, L.P., which is 410 Park Avenue, New York, New York 10022; ClearBridge Advisors, LLC which is 399 Park Avenue, New York, New York 10022; Barclays Global Investors, NA which is 45 Fremont Street, San Francisco, California 94105; and Alson Capital Partners, LLC which is 810 7th Avenue, 39th Floor, New York, New York 10019.

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

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

(4) As reported on Schedule 13G filed with the SEC in a joint filing with Alson Signature Fund, L.P., Alson Signature Fund I, L.P., Alson Signature Fund Offshore Portfolio, Ltd. and Alson Nucleus Fund, L.P.

(5) 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.

(6) 600 of these shares are held by the M. I. Purgason Trust, of which Mr. Purgason serves as co-trustee.

(7) 1,000 of these shares are held by the James C. Crain Trust.

(8) 169,457 shares are held by Murchison Capital Partners, L.P. Mr. Murchison is the President of the Murchison Management Corp., which serves as the general partner of Murchison Capital Partners, L.P.

Beneficial Ownership of General Partner Interest

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

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

Our General Partner

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

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

Relationship with Crosstex Energy, Inc.

General. CEI owns 16,414,830 common units, representing approximately 36% limited partnership interest in us. Our general partner owns a 2% general partner interest in us and the incentive distribution rights. Our general partner's ability, as general partner, to manage and operate Crosstex Energy, L.P. and Crosstex Energy, Inc.'s ownership in us effectively gives our general partner the ability to veto some of our actions and to control our management. Crosstex Energy, Inc. pays us for administrative and compensation costs that we incur on its behalf. During 2007, this fee was approximately $47,500 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. The noncompetition restrictions in the omnibus agreement do not apply to the assets retained and business conducted by CEI at the closing of our initial public offering. Except as provided above, CEI and its controlled affiliates are not prohibited from engaging in activities in which they compete directly with us.

Related Party Transactions

Crosstex Denton County Gathering J.V. We own a 50% interest, before application of any dilution rights, in Crosstex Denton County Gathering, J.V. (CDC). CDC was formed to build, own and operate a natural gas gathering system in Denton County, Texas. We manage the business affairs of CDC. The other joint venture partner (the CDC Partner) is an unrelated third party who owns and operates the natural gas field located in Denton County. In connection with the formation of CDC, we agreed to loan the CDC Partner up to $1.5 million for their initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to us attributable to CDC Partner's share of distributable cash flow to repay the loan. Any balance remaining on the note is due in August 2008.

Reimbursement of Costs by CEI. CEI paid us $0.6 million, $0.5 million and $0.3 million during the years ended December 31, 2007, 2006 and 2005, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI.

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

Item 14. *Principal Accounting Fees and Services*

Audit Fees

The fees for professional services rendered for the audit of our annual financial statements for each of the fiscal years ended December 31, 2007 and December 31, 2006, review of our internal control procedures for the fiscal year ended December 31, 2007 and December 31, 2006, 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 and $1.5 million, respectively. 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, 2007 and December 31, 2006 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, 2007 and December 31, 2006.

All Other Fees

KPMG did not render services to us, other than those services covered in the sections captioned "Audit Fees" and "Tax Fees" for the fiscal years ended December 31, 2007 and December 31, 2006.

Audit Committee Approval of Audit and Non-Audit Services

All audit and non-audit services and any services that exceed the annual limits set forth in the policy must be pre-approved by the Audit Committee. In 2008, 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-44.

(3) Exhibits

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

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
3.3	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.4	—	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).
3.5	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.6	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	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).
3.8	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
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).

Number		Description
4.2	—	Specimen Unit Certificate for the Senior Subordinated Series C Units (incorporated by reference to Exhibit 4.8 to our Registration Statement on Form S-3, file No. 333-135951).
4.3	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LBI Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
4.4	—	Registration Rights Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
10.1	—	Fourth Amended and Restated Credit Agreement, dated November 1, 2005, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.2	—	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).
10.3	—	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.4	—	Third Amendment to Fourth Amended and Restated Credit Agreement, effective as of March 28, 2007, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.5	—	Commitment Increase Agreement, dated as of September 19, 2007, among Crosstex Energy, L.P., Bank of America, N.A., and certain lenders party thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated September 19, 2007, filed with the Commission on September 24, 2007).
10.6	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
10.7	—	Letter Amendment No. 1 to Amended and Restated Note Purchase Agreement, effective as of March 30, 2007, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.8	—	Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.9†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan, dated July 12, 2002 (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2002).
10.10†	—	Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).

Number		Description
10.11	—	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).
10.12†	—	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).
10.13	—	Senior Subordinated Series C Unit Purchase Agreement, dated as of May 16, 2006, by and among Crosstex Energy, L.P. and each of the Purchasers thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 16, 2006, filed with the Commission on May 17, 2006).
10.14	—	Seminole Gas Processing Plant Gaines County, Texas Joint Operating Agreement dated January 1, 1993 (incorporated by reference to Exhibit 10.10 to our Registration Statement on Form S-1, file No. 333-106927).
10.15	—	Senior Subordinated Series D Unit Purchase Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
10.16†	—	Form of Performance Unit Agreement (incorporated by reference to our current report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007).
21.1*	—	List of Subsidiaries.
23.1*	—	Consent of KPMG LLP.
31.1*	—	Certification of the Principal Executive Officer.
31.2*	—	Certification of the Principal Financial Officer.
32.1*	—	Certification of the Principal Executive Officer and the Principal Financial Officer of the Company pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 29th day of February 2008.

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 29, 2008
/s/ RHYS J. BEST Rhys J. Best	Director	February 29, 2008
/s/ JAMES C. CRAIN James C. Crain	Director	February 29, 2008
/s/ LELDON E. ECHOLS Leldon E. Echols	Director	February 29, 2008
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Chairman of the Board	February 29, 2008
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	February 29, 2008
/s/ CECIL E. MARTIN Cecil E. Martin	Director	February 29, 2008
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	February 29, 2008
/s/ KYLE D. VANN Kyle D. Vann	Director	February 29, 2008
/s/ WILLIAM W. DAVIS William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 29, 2008

INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Crosstex Energy GP, LLC is responsible for establishing and maintaining adequate internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting for Crosstex Energy, L.P. (the "Partnership"). As defined by the Securities and Exchange Commission (Rule 13a-15(f) under the 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, 2007, 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, 2007, 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 management's assessment of internal control over financial reporting, a copy of which appears on page F-3 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, 2007 and 2006 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, 2007. 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, 2007 and 2006 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, 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.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, Crosstex Energy, L.P. and subsidiaries adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), *Share Based Payment.*

We also have 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, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 29, 2008, expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 29, 2008

The Partners
Crosstex Energy, L.P.:

We have audited Crosstex Energy L.P.'s internal control over financial reporting as of December 31, 2007, 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, 2007, 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, 2007 and 2006, and the related consolidated statements of operations, stockholders' equity and comprehensive income, and cash flows for each of the years in three-year period ended December 31, 2007, and our report dated February 29, 2008, expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 29, 2008

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets

	December 31, 2007	December 31, 2006
	(In thousands except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 142	$ 824
Accounts receivable:		
Trade, net of allowance for bad debts of $985 and $618, respectively	46,441	35,787
Accrued revenues	443,448	331,236
Imbalances	3,865	5,159
Affiliated companies	38	23
Note receivable	1,026	926
Other	2,531	2,864
Fair value of derivative assets	8,589	23,048
Natural gas and natural gas liquids, prepaid expenses and other	16,062	10,468
Total current assets	522,142	410,335
Property and equipment:		
Transmission assets	468,692	335,599
Gathering systems	460,420	285,706
Gas plants	565,415	460,774
Other property and equipment	64,073	30,816
Construction in process	79,889	129,373
Total property and equipment	1,638,489	1,242,268
Accumulated depreciation	(213,327)	(136,455)
Total property and equipment, net	1,425,162	1,105,813
Fair value of derivative assets	1,337	3,812
Intangible assets, net of accumulated amortization of $60,118 and $31,673, respectively	610,076	638,602
Goodwill	24,540	24,495
Other assets, net	9,617	11,417
Total assets	$ 2,592,874	$ 2,194,474
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 28,931	$ 47,948
Accounts payable	13,727	31,764
Accrued gas purchases	427,293	325,151
Accrued imbalances payable	9,447	2,855
Accrued construction in process costs	12,732	29,942
Fair value of derivative liabilities	21,066	12,141
Current portion of long-term debt	9,412	10,012
Other current liabilities	46,422	30,458
Total current liabilities	569,030	490,271
Long-term debt	1,213,706	977,118
Other long-term liabilities	3,553	—
Deferred tax liability	8,518	8,996
Minority interest	3,815	3,654
Fair value of derivative liabilities	9,426	2,558
Commitments and contingencies	—	—
Partners' equity:		
Common unitholders (23,868,041 and 19,616,172 units issued and outstanding at December 31, 2007 and 2006, respectively)	337,171	330,492
Subordinated unitholders (4,668,000 and 7,001,000 units issued and outstanding at December 31, 2007 and 2006, respectively)	(14,679)	(6,402)
Senior subordinated C unitholders (12,829,650 units issued and outstanding at December 31, 2007 and 2006)	359,319	359,319
Senior subordinated D unitholders (3,875,340 units issued and outstanding at December 31, 2007)	99,942	—
General partner interest (2% interest with 923,286 and 805,037 equivalent units outstanding at December 31, 2007 and 2006, respectively)	24,551	20,472
Accumulated other comprehensive income	(21,478)	7,996
Total partners' equity	784,826	711,877
Total liabilities and partners' equity	$ 2,592,874	$ 2,194,474

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Years Ended December 31, 2007	2006	2005
	(In thousands except per unit data)		
Revenues:			
Midstream	$ 3,791,316	$ 3,075,481	$ 2,982,874
Treating	65,025	63,813	48,606
Profit on energy trading activities	4,090	2,510	1,568
Total revenues	3,860,431	3,141,804	3,033,048
Operating costs and expenses:			
Midstream purchased gas	3,468,924	2,859,815	2,860,823
Treating purchased gas	7,892	9,463	9,706
Operating expenses	127,759	100,991	56,736
General and administrative	61,528	45,694	32,697
(Gain) loss on derivatives	(5,666)	(1,599)	9,968
Gain on sale of property	(1,667)	(2,108)	(8,138)
Depreciation and amortization	108,880	82,731	36,024
Total operating costs and expenses	3,767,650	3,094,987	2,997,816
Operating income	92,781	46,817	35,232
Other income (expense):			
Interest expense, net of interest income	(78,451)	(51,427)	(15,767)
Other income	683	183	392
Total other income (expense)	(77,768)	(51,244)	(15,375)
Income (loss) before minority interest and taxes	15,013	(4,427)	19,857
Minority interest in subsidiary	(160)	(231)	(441)
Income tax provision	(964)	(222)	(216)
Net income (loss) before cumulative effect of change in accounting principle	13,889	(4,880)	19,200
Cumulative effect of change in accounting principle	—	689	—
Net income (loss)	$ 13,889	$ (4,191)	$ 19,200
General partner interest in net income	$ 19,252	$ 16,456	$ 8,652
Limited partners' interest in net income (loss)	$ (5,363)	$ (20,647)	$ 10,548
Net income (loss) before cumulative effect of change in accounting principle per limited partners' unit (see Note 9(e)):			
Basic common unit	$ (0.20)	$ (1.12)	$ 0.56
Diluted common unit	$ (0.20)	$ (1.12)	$ 0.51
Basic and diluted senior subordinated A unit (see Note 9(e))	$ —	$ 5.31	$ —
Basic and diluted senior subordinated series C and D units (see Note 9(e))	$ —	$ —	$ —
Net income (loss) per limited partners' unit:			
Basic common unit	$ (0.20)	$ (1.09)	$ 0.56
Diluted common unit	$ (0.20)	$ (1.09)	$ 0.51
Basic and diluted senior subordinated A unit (see Note 9(e))	$ —	$ 5.31	$ —
Basic and diluted senior subordinated series C and D units (see 9(e))	$ —	$ —	$ —

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Changes in Partners' Equity
Years ended December 31, 2007, 2006 and 2005

	Common Units		Subordinated Units		Sr. Subordinated Units		Sr. Subordinated C Units		Sr. Subordinated D Units		General Partner Interest		Accumulated Other Comprehensive Income	Total
	$	Units	$	Units	$	Units	$	Units	$	Units	$	Units		
							(In thousands)							
Balance, December 31, 2004	$ 111,960	8,755	$ 28,002	9,334	$ —	—	$ —	—	$ —	—	$ 4,078	369	$ 10	$144,050
Issuance of common units(1)	223,340	6,581	—	—	—	—	—	—	—	—	—	—	—	223,340
Issuance of Sr. subordinated units	—	—	—	—	$ 49,921	1,495	—	—	—	—	—	—	—	49,921
Proceeds from exercise of common unit options	1,345	129	—	—	—	—	—	—	—	—	—	—	—	1,345
Capital contributions	—	—	—	—	—	—	—	—	—	—	6,311	168	—	6,311
Stock-based compensation	1,798	—	—	—	—	—	—	—	—	—	1,874	—	—	3,672
Distributions	(16,459)	—	(17,455)	—	—	—	—	—	—	—	(9,393)	—	—	(43,307)
Net income	4,633	—	5,915	—	—	—	—	—	—	—	8,652	—	—	19,200
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	—	—	7,864	7,864
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	(11,111)	(11,111)
Balance, December 31, 2005	326,617	15,465	16,462	9,334	49,921	1,495	—	—	—	—	11,522	537	(3,237)	401,285
Proceeds from exercise of unit options	3,328	305	—	—	—	—	—	—	—	—	—	—	—	3,328
Issuance of Sr. subordinated C units	—	—	—	—	—	—	359,319	12,830	—	—	—	—	—	359,319
Conversion of subordinated units	52,195	3,829	(2,274)	(2,333)	(49,921)	(1,495)	—	—	—	—	—	—	—	—
Conversion of common units for restricted units	—	17	—	—	—	—	—	—	—	—	—	—	—	—
Capital contributions	—	—	—	—	—	—	—	—	—	—	9,273	268	—	9,273
Stock-based compensation	3,122	—	1,114	—	—	—	—	—	—	—	3,632	—	—	7,868
Distributions	(39,725)	—	(16,102)	—	—	—	—	—	—	—	(20,411)	—	—	(76,238)
Net income (loss)	(15,045)	—	(5,602)	—	—	—	—	—	—	—	16,456	—	—	(4,191)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	—	—	(4,875)	(4,875)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	16,108	16,108
Balance, December 31, 2006	330,492	19,616	(6,402)	7,001	—	—	359,319	12,830	—	—	20,472	805	7,996	711,877
Issuance of common units	57,550	1,800	—	—	—	—	—	—	—	—	—	—	—	57,550
Proceeds from exercise of unit options	1,598	90	—	—	—	—	—	—	—	—	—	—	—	1,598
Issuance of Sr. subordinated D units	—	—	—	—	—	—	—	—	99,942	3,875	—	—	—	99,942
Conversion of subordinated units	(3,872)	2,333	3,872	(2,333)	—	—	—	—	—	—	—	—	—	—
Conversion of restricted units for common units, net of units withheld for taxes	(329)	29	—	—	—	—	—	—	—	—	—	—	—	(329)
Capital contributions	—	—	—	—	—	—	—	—	—	—	4,014	118	—	4,014
Stock-based compensation	5,478	—	1,228	—	—	—	—	—	—	—	5,578	—	—	12,284
Distributions	(49,810)	—	(11,950)	—	—	—	—	—	—	—	(24,765)	—	—	(86,525)
Net income (loss)	(3,936)	—	(1,427)	—	—	—	—	—	—	—	19,252	—	—	13,889
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	—	—	(3,706)	(3,706)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	(25,768)	(25,768)
Balance, December 31, 2007	$ 337,171	23,868	$ (14,679)	4,668	$ —	—	$ 359,319	12,830	$ 99,942	3,875	$ 24,551	923	$ (21,478)	$784,826

(1) Includes Senior Subordinated Series B Units which automatically converted to common units fourteen days after issuance. See Note 7(a).

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Years Ended December 31,		
	2007	2006	2005
		(In thousands)	
Net income (loss)	$ 13,889	$ (4,191)	$ 19,200
Hedging gains or losses reclassified to earnings	(3,706)	(4,875)	7,864
Adjustment in fair value of derivatives	(25,768)	16,108	(11,111)
Comprehensive income (loss)	$ (15,585)	$ 7,042	$ 15,953

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31, 2007	2006	2005
		(In thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 13,889	$ (4,191)	$ 19,200
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	108,880	82,731	36,024
Non-cash stock-based compensation	12,284	8,557	3,672
Cumulative effect of change in accounting principle	—	(689)	—
Gain on sale of property	(1,667)	(2,108)	(8,138)
Deferred tax expense	253	490	216
Minority interest in subsidiary	160	231	441
Non-cash derivatives loss	2,418	550	10,208
Amortization of debt issue costs	2,639	2,694	1,127
Changes in assets and liabilities, net of acquisition effects:			
Accounts receivable, accrued revenue and other	(121,300)	77,365	(165,990)
Natural gas and natural gas liquids, prepaid expenses and other	(5,566)	13,071	(1,719)
Accounts payable, accrued gas purchases and other accrued liabilities	101,993	(65,691)	132,932
Fair value of derivatives	835	—	(13,963)
Net cash provided by operating activities	114,818	113,010	14,010
Cash flows from investing activities:			
Additions to property and equipment	(414,452)	(314,766)	(120,490)
Acquisitions and asset purchases	—	(576,110)	(505,518)
Proceeds from sales of property	3,070	5,051	10,991
Net cash used in investing activities	(411,382)	(885,825)	(615,017)
Cash flows from financing activities:			
Proceeds from borrowings	1,189,500	1,708,500	1,798,250
Payments on borrowings	(953,512)	(1,244,021)	(1,424,300)
Capital lease obligations	3,553	—	—
Increase (decrease) in drafts payable	(19,017)	18,094	(8,812)
Debt refinancing costs	(892)	(5,646)	(6,919)
Distributions to minority interest party	—	(375)	786
Distribution to partners	(86,525)	(76,238)	(43,307)
Proceeds from exercise of unit options	1,598	3,328	1,345
Net proceeds from common unit offerings	57,550	—	223,340
Net proceeds from issuance of subordinated units	99,942	359,319	49,915
Contribution from partners	4,014	9,273	6,317
Restricted units withheld for taxes	(329)	—	—
Net cash provided by financing activities	295,882	772,234	596,615
Net increase (decrease) in cash and cash equivalents	(682)	(581)	(4,392)
Cash and cash equivalents, beginning of period	824	1,405	5,797
Cash and cash equivalents, end of period	$ 142	$ 824	$ 1,405
Cash paid for interest	$ 79,648	$ 46,794	$ 14,598
Cash paid (refund) for income taxes	$ 38	$ (847)	$ 496

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements
December 31, 2007 and 2006

(1) Organization and Summary of Significant Agreements

(a) Description of Business

Crosstex Energy, L.P., A Delaware limited partnership formed on July 12, 2002, is engaged in the gathering, transmission, treating, processing and marketing of natural gas and natural gas liquids (NGLs). The Partnership connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of NGLs, transports natural gas and NGLs and ultimately provides natural gas and NGLs to a variety of markets. In addition, the Partnership purchases natural gas and NGLs from producers not connected to its gathering systems for resale and sells 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, 2007, CEI also owns 4,668,000 subordinated units, 6,414,830 senior subordinated series C units and 5,332,000 common units in the Partnership through its wholly-owned subsidiaries. As of December 31, 2007, CEI owned 36.3% of the limited partner interests in the Partnership and officers and directors owned 1.20% of the limited partnership interests. The remaining units are held by the public. As of December 31, 2007, Crosstex Energy Services (CES) management and directors owned 7.87% of CEI.

In February 2008, 4,668,000 of CEI's subordinated units and 6,414,830 Senior Subordinated Series C units converted to common units so that the ownership of common units is 16,414,830 as of February 16, 2008.

(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 12.4% interest in a carbon dioxide processing plant acquired by the Partnership in June 2004 and its undivided 59.27% interest in a gas plant acquired by the Partnership in November 2005 (23.85%) and May 2006 (35.42%). In January 2004, the Partnership adopted FASB Interpretation No. 46R, *Consolidation of Variable Interest Entities* (FIN No. 46R) and began consolidating its joint venture interest in Crosstex DC Gathering, J.V. (CDC) as discussed more fully in Note 4. 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 natural gas liquids. The Partnership reports these assets at the lower of cost or market.

(d) Property, Plant, and Equipment

Property, plant and equipment consist of intrastate gas transmission systems, gas gathering systems, industrial supply pipelines, NGL pipelines, natural gas processing plants, NGL fractionation plants, an undivided 12.4% interest in a carbon dioxide processing plant, dew point control and gas treating plants.

Other property and equipment is primarily comprised of computer software and equipment, furniture, fixtures, leasehold improvements and office equipment. Property, plant and equipment are recorded at cost. Gas required to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest costs are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use. Interest costs totaling $4.8 million, $5.4 million, and $0.9 million were capitalized for the years ended December 31, 2007, 2006 and 2005, respectively.

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

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

Depreciation expense of $80.4 million, $68.9 million and $31.7 million was recorded for the years ended December 31, 2007, 2006 and 2005, respectively.

Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Partnership compares the net book value of the asset to the undiscounted expected future net cash flows. If 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. No impairments were incurred during the three-year period ended December 31, 2007.

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.

(e) Goodwill and Intangibles

The Partnership has approximately $24.5 million of goodwill at December 31, 2007 and 2006. During the formation of the Partnership in May 2001, $5.4 million of goodwill was created and later amortized by $0.5 million.

Approximately $1.7 million and $1.4 million of goodwill resulted from the two Cardinal acquisitions in May 2005 and October 2006, respectively. Approximately $16.5 million of goodwill resulted from the Hanover acquisition in February 2006. The goodwill related to the formation of the Partnership has been allocated to the Midstream segment and the goodwill resulting from the Cardinal and Hanover acquisitions is allocated to the Treating segment. Goodwill is assessed at least annually for impairment. During the fourth quarter of 2007, the Partnership completed the annual impairment testing of goodwill and no impairment was incurred.

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

Amortization of intangibles was approximately $28.5 million, $13.9 million and $4.3 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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

2008	$ 32,582
2009	42,222
2010	45,548
2011	47,356
2012	49,443
Thereafter	392,925
Total	$ 610,076

(f) Other Assets

Unamortized debt issuance costs totaling $9.6 million and $11.4 million as of December 31, 2007 and 2006, 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 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. The Partnership had imbalance payables of $9.4 million and $2.9 million at December 31, 2007 and 2006, respectively, which approximate the fair value of these imbalances. The Partnership had imbalance receivables of $3.9 million and $5.2 million at December 31, 2007 and 2006, respectively, which are carried at the lower of cost or market value.

(h) Asset Retirement Obligations

In March 2005, the FASB issued Interpretation No. 47, "*Accounting for Conditional Asset Retirement Obligations*" (FIN 47) which became effective at December 31, 2005. FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, "*Accounting for Asset Retirement Obligations*", refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FIN 47 provides that a liability for the fair value of a conditional asset retirement activity should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB Statement No. 143. The Partnership did not provide any asset retirement obligations as of December 31, 2007 or 2006 because it does not have sufficient information as set forth in FIN 47 to reasonably estimate such obligations and the Partnership has no current intention of discontinuing use of any significant assets.

(i) Revenue Recognition

The Partnership recognizes revenue for sales or services at the time the natural gas, carbon dioxide, or NGLs are delivered or at the time the service is performed. The Partnership generally accrues one to two months of sales and the related gas purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates.

The Partnership's purchase and sale arrangements are generally reported in revenues and costs on a gross basis in the statements of operations in accordance with EITF Issue No. 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Except for fee based arrangements and the Partnership's energy trading activities related to its "off-system" gas marketing operations discussed in Note 2(k), the Partnership acts as the principal in these purchase and sale transactions, has the risk and reward of ownership as evidenced by title transfer, schedules the transportation and assumes credit risk.

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

(j) Derivatives

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

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

(k) Energy Trading Activities

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

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

Net margins earned on settled contracts from its energy trading activities included in profit on energy trading activities in the consolidated statement of operations were $4.1 million, $2.5 million and $1.6 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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

	Years Ended December 31,		
	2007	2006	2005
Volumes purchased and sold	34,432,000	50,563,000	66,065,000

(l) Comprehensive Income (Loss)

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

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

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

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

(n) 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 $337.8 million as of December 31, 2007. Effective January 1, 2007, the Partnership is subject to the gross margin tax enacted by the state of Texas on May 1, 2006. The new tax law had no significant impact on the Partnership's deferred tax liability.

The LIG entities the Partnership formed to acquire the stock of LIG Pipeline Company and its subsidiaries, as discussed more fully in Note 3, 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 has been utilized in 2007.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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).

	2007	2006	2005
Current tax provision (benefit)	$ 711	$ (268)	—
Deferred tax provision (benefit)	253	490	$ 216
	$ 964	$ 222	$ 216
A reconciliation of the provision for income taxes for the taxable corporation is as follows (in thousands):			
Federal income tax on taxable corporation at statutory rate (35)%	206	$ 206	$ 206
State income taxes, net	758	16	10
Tax provision (benefit)	$ 964	$ 222	$ 216

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

	Years Ended December 31, 2007	2006
Deferred income tax assets:		
Net operating loss carryforward — current	$ 4	$ 718
Net operating loss carryforward — long-term	61	49
Alternative minimum tax credit carryover — long-term	99	59
	$ 164	$ 826
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets-current	$ (501)	$ (501)
Property, plant, equipment and intangible assets-long-term	(8,678)	(9,103)
	(9,179)	$ (9,604)
Net deferred tax liability	$ (9,015)	$ (8,778)

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

(o) 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, 2007, 2006 and 2005 of $1.0 million, $0.6 million and $0.3 million, respectively.

During 2007 and 2006, Dow Hydrocarbons accounted for 11.8% and 13.4%, respectively, of the consolidated revenue of the Partnership. During 2005, Formosa Hydrocarbons accounted for 10.6% of the consolidated revenue. As the Partnership continues to grow and expand, this relationship between individual customer sales and consolidated total sales is expected to continue to change. While these customers represent a significant percentage of revenues, the loss of either would not have a material adverse impact on the Partnership results of operations.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

(p) Environmental Costs

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or discounted when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For years ended December 31, 2007, 2006 and 2005, such expenditures were not significant.

(q) Option Plans

Effective January 1, 2006, the Partnership adopted the provisions of SFAS No. 123R, "*Share-Based Payment"* (FAS No. 123R) which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. The Partnership applied the provisions of Accounting Principles Board Opinion No. 25, "*Accounting for Stock Issued to Employees"* (APB No. 25), for periods prior to January 1, 2006. In accordance with APB No. 25 for fixed stock and unit options, compensation expense was recorded prior to 2006 to the extent the market value of the stock or unit exceeded the exercise price of the option at the measurement date. Compensation expense for fixed awards with pro rata vesting was recognized on a straight-line basis over the vesting period. In addition, compensation expense was recorded for variable options based on the difference between fair value of the stock or unit and exercise price of the options at period end.

The Partnership elected to use the modified-prospective transition method for adopting SFAS No. 123R. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under SFAS No. 123R. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with SFAS No. 123R. The Partnership adjusted compensation cost for actual forfeitures as they occurred under APB No. 25 for periods prior to January 1, 2006. Under SFAS No. 123R, the Partnership is required to estimate forfeitures in determining periodic compensation cost. The cumulative effect of the adoption of SFAS No. 123R recognized on January 1, 2006 was an increase in net income of $0.7 million due to the reduction in previously recognized compensation costs associated with the estimation of forfeitures.

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

	Years Ended December 31,		
	2007	2006	2005
Cost of share-based compensation charged to general and administrative expense	$ 10,442	$ 7,426	$ 3,659
Cost of share-based compensation charged to operating expense	1,842	1,131	398
Total amount charged to income before cumulative effect of accounting change	$ 12,284	$ 8,557	$ 4,057

Share-based compensation expense recorded in 2005 included $0.5 million related to the accelerated vesting of 7,060 common unit options and 10,000 CEI common share options.

Had compensation cost for the Partnership been determined based on the fair value at the grant date for awards in accordance with SFAS No. 123, *Accounting for Stock Based Compensation* for the year ended December 31, 2005 the Partnership's net income would have been as follows (in thousands except per unit amounts):

		Year Ended December 31, 2005
Net income, as reported	$	19,200
Add: Stock-based employee compensation expense included in reported net income		4,057
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards		(4,445)
Pro forma net income	$	18,812
Net income per limited partner unit, as reported:		
Basic	$	0.56
Diluted	$	0.51
Pro forma net income per limited partner unit:		
Basic	$	0.53
Diluted	$	0.50

The fair value of each option is estimated on the date of grant using the Black Scholes option-pricing model as disclosed in Note (9) — Employee Incentive Plans.

(r) Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), *"Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109,"* which we adopted effective January 1, 2007. FIN 48 addressed the determination of how tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under FIN 48, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The adoption of FIN 48 had no material impact to our financial statements. At December 31, 2007, we have no material assets, liabilities or accrued interest and penalties associated with uncertain tax positions. 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, 2007, tax years 2000 through 2007 remain subject to examination by the Internal Revenue Service and applicable states. We do not expect any material change in the balance of our unrecognized tax benefits over the next twelve months.

On September 13, 2006, the Securities Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108 (SAB 108), which establishes an approach that requires quantification of financial statement errors based on the effects of the error on each of the company's financial statements and the related disclosures. SAB 108 requires the use of a balance sheet and an income statement approach to evaluate whether either of these approaches results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. We adopted SAB 108 effective October 1, 2006 with no material impact on our financial statements.

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, *"Fair Value Measurements"* (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. While SFAS 157 does not add any new fair value measurements, it is intended to increase consistency and comparability of such measurement. The provisions of SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The adoption of this standard will not have a material impact on our results of operations, financial position or cash flows.

In February 2007, the FASB issued SFAS No. 159, *"Fair Value Option for Financial Assets and Financial Liabilities-Including an amendment to FASB Statement No. 115"* (SFAS 159) permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. SFAS 159 is effective for fiscal years beginning after November 15, 2007. The adoption of SFAS 159 will have no material impact on our financial statements.

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

(3) Significant Asset Purchases and Acquisitions

In November 2005, the Partnership acquired El Paso Corporation's processing and natural gas liquids business in south Louisiana for $481.0 million. The assets acquired include 2.3 billion cubic feet per day of processing capacity, 66,000 barrels per day of fractionation capacity, 2.4 million barrels of underground storage and 400 miles of liquids transport lines. The Partnership financed the acquisition with net proceeds totaling $228.0 million from the issuance of common units and senior subordinated series B units (including the 2% general partner contributions totaling $4.7 million) and borrowing under its bank credit facility for the remaining balance.

On June 29, 2006, the Partnership expanded its operations in the north Texas area through the acquisition of the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems, which we refer to in conjunction with the NTP and other facilities in the area as the north Texas assets, included gathering pipeline, a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. Simultaneously with the Chief Acquisition, the Partnership entered into a gas gathering agreement with Devon Energy Corporation (Devon) whereby the Partnership has agreed to gather, and Devon has agreed to dedicate and deliver, the future production on acreage that Devon acquired from Chief (approximately 160,000 net acres). Under the agreement, Devon has committed to deliver all of the production from the dedicated acreage into the gathering system, including production from current wells and wells that it drills in the future. The Partnership will expand the gathering system to reach the new wells as they are drilled. The agreement has a 15-year term and provides for fixed gathering fees over the term. In addition to the Devon agreement, approximately 60,000 additional net acres were dedicated to the NTG Assets under agreements with other producers.

The Partnership utilized the purchase method of accounting for the acquisition of the NTG Assets with an acquisition date of June 29, 2006. The Partnership recognizes the gathering fee income received from Devon and other producers who deliver gas into the NTG Assets as revenue at the time the natural gas is delivered. The purchase price and allocation thereof are as follows (in thousands):

Cash paid to Chief	$	474,858
Direct acquisition costs		429
Total purchase price	$	475,287
Assets acquired:		
Current assets	$	18,833
Property, plant and equipment		115,728
Intangible assets		395,604
Liabilities assumed:		
Current liabilities		(54,878)
Total purchase price	$	475,287

Intangibles relate primarily to the value of the dedicated and non-dedicated acreage attributable to the system, including the agreement with Devon, and are being amortized using the units of throughput method of amortization. Pursuant to the purchase and sale agreement with Chief (the PSA), the purchase price paid to Chief included reimbursement for the certain capital expenditures related to the expansion of the gathering system incurred by Chief during first half of 2006, subject to our review such capital expenditures. In June 2007, the Partnership completed its detail review of such capital expenditures and determined that certain of the costs reimbursed to Chief were not in accordance with the PSA and made a claim for reimbursement from Chief. The Partnership was successful in negotiating and collecting a settlement of approximately $7 million related to this claim in January 2008. This collection of this settlement was not accrued as part of the purchase price and will be recognized in income when realized during the first quarter of 2008.

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

Operating results for the Chief acquisition have been included in the consolidated statements of operations since June 29, 2006. The following unaudited pro forma results of operations assume that the Chief acquisition occurred on January 1, 2006 (in thousands, except per unit amounts):

		Pro Forma Year Ended December 31, 2006 (Unaudited)
Revenue	$	3,155,854
Net income (loss)	$	(8,808)
Net income (loss) per limited partner unit		
Basic and diluted common units	$	(1.26)
Basic and diluted senior subordinated A unit	$	5.31
Weighted average limited partners' units outstanding		
Basic and diluted common units		26,337
Basic and diluted senior subordinated A unit		1,495

There are substantial differences in the way Chief operated the NTG Assets during pre-acquisition periods and the way the Partnership operates these assets post-acquisition. Although the unaudited pro forma results of operations include adjustments to reflect the significant effects of the acquisition, these pro forma results do not purport to present the results of operations had the acquisition actually been completed as of January 1, 2006.

(4) Investment in Limited Partnerships and Note Receivable

The Partnership owns a 50% interest in CDC and consolidates its investment in CDC pursuant to FIN No. 46R. The Partnership manages the business affairs of CDC. The other 50% joint venture partner (the CDC partner) is an unrelated third party who owns and operates a natural gas field located in Denton County.

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 50% share of distributable cash flow to repay the loan. Any balance remaining on the note is due in August 2008. The balance remaining on the note of $1.0 million is included in current notes receivable as of December 31, 2007.

(5) Long-Term Debt

As of December 31, 2007 and 2006, long-term debt consisted of the following (in thousands):

	2007	2006
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2007 and 2006 were 6.71% and 7.20%, respectively	$ 734,000	$ 488,000
Senior secured notes, weighted average interest rates at December 31, 2007 and 2006 of 6.75% and 6.76%, respectively	489,118	498,530
Note payable to Florida Gas Transmission Company	—	600
	1,223,118	987,130
Less current portion	(9,412)	(10,012)
Debt classified as long-term	$ 1,213,706	$ 977,118

Credit Facility. In September 2007, the Partnership increased borrowing capacity under the bank credit facility to $1.185 billion. The bank credit facility matures in June 2011. As of December 31, 2007, $861.3 million was outstanding under the bank credit facility, including $127.3 million of letters of credit, leaving approximately $323.7 million available for future borrowing.

Obligations under the bank credit facility are secured by first priority liens on all of the Partnership's material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of the Partnership's equity interests in certain of its subsidiaries, and rank *pari passu* in right of payment with the senior secured notes. The bank credit facility is guaranteed by certain of the Partnership's subsidiaries. The Partnership may prepay all loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements.

Under the amended credit agreement, borrowings bear interest at the Partnership's option at the administrative agent's reference rate plus 0% to 0.25% or LIBOR plus 1.00% to 1.75%. The applicable margin varies quarterly based on the Partnership's leverage ratio. The fees charged for letters of credit range from 1.00% to 1.75% per annum, plus a fronting fee of 0.125% per annum. The Partnership will incur quarterly commitment fees ranging from 0.20% to 0.375% on the unused amount of the credit facilities.

The credit agreement prohibits the Partnership from declaring distributions to unit-holders if any event of default, as defined in the credit agreement, exists or would result from the declaration of distributions. In addition, the bank credit facility contains various covenants that, among other restrictions, limit the Partnership's ability to:

- incur indebtedness;

- grant or assume liens;
- make certain investments;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make distributions;
- change the nature of its business;
- enter into certain commodity contracts;
- make certain amendments to the Partnership's or its operating partnership's partnership agreement; and
- engage in transactions with affiliates.

In April 2007, the Partnership amended its bank credit facility, effective as of March 28, 2007, to increase the maximum permitted leverage ratio for the fiscal quarter ending September 30, 2007 and each fiscal quarter thereafter. The maximum leverage ratio (total funded debt to consolidated earnings before interest, taxes, depreciation and amortization) is as follows (provided, however, that during an acquisition period as defined in the bank credit facility, the maximum leverage ratio shall be increased by 0.50 to 1.00 from the otherwise applicable ratio set forth below):

- 5.25 to 1.00 for fiscal quarters through December 31, 2007;
- 5.00 to 1.00 for any fiscal quarter ending March 31, 2008 through September 2008;
- 4.75 to 1.00 for fiscal quarters ending December 31, 2008 and March 31, 2009; and
- 4.50 to 1.00 for any fiscal quarter ending thereafter.

Additionally, the bank credit facility now provides that (i) if the Partnership or its subsidiaries incur unsecured note indebtedness, the leverage ratio will shift to a two-tiered structure and (ii) during periods where the Partnership has outstanding unsecured note indebtedness, the Partnership's leverage ratio cannot exceed 5.50 to 1.00 and the Partnership's senior leverage ratio cannot exceed 4.50 to 1.00. The other material terms and conditions of the credit facility remained unchanged.

The bank credit facility contains the following covenants requiring the Partnership to maintain:

- a minimum interest coverage ratio (as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, equal to 3.0 to 1.0.

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

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

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. See Note (11) to the financial statements for a discussion of interest rate swaps.

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

Month Issued	Amount	Interest Rate	Maturity	Principal Payment Terms
June 2003	$ 30,000	6.95%	7 years	Quarterly payments of $1,765 from June 2006-June 2010
July 2003	10,000	6.88%	7 years	Quarterly payments of $588 from July 2006-July 2010
June 2004	75,000	6.96%	10 years	Annual payments of $15,000 from July 2010-July 2014
November 2005	85,000	6.23%	10 years	Annual payments of $17,000 from November 2010-December 2014
March 2006	60,000	6.32%	10 years	Annual payments of $12,000 from March 2012-March 2016
July 2006	245,000	6.96%	10 years	Annual payments of $49,000 from July 2012-July 2016
Total Issued	505,000			
Principal repaid	(15,882)			
Balance as of December 31, 2007	$ 489,118			

In April 2007, the Partnership amended the senior note agreement, effective as of March 30, 2007, to (i) provide that if the Partnership's leverage ratio at the end of any fiscal quarter exceeds certain limitations, the Partnership will pay the holders of the senior secured notes an excess leverage fee based on the daily average outstanding principal balance of the senior secured notes during such fiscal quarter multiplied by certain percentages set forth in the senior note agreement; (ii) increase the rate of interest on each senior secured note by 0.25% if, at any given time during an acquisition period (as defined in the senior note agreement), the leverage ratio exceeds 5.25 to 1.00; (iii) cause the leverage ratio to shift to a two-tiered structure if the Partnership or its subsidiaries incur unsecured note indebtedness; and (iv) limit the Partnership's leverage ratio to 5.25 to 1.00 and the Partnership's senior leverage ratio to 4.25 to 1.00 during periods where the Partnership has outstanding unsecured note indebtedness. The other material items and conditions of the senior note agreement remained unchanged.

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

The $40.0 million of senior secured notes issued in 2003 are redeemable, at the Partnership's option and subject to certain notice requirements, at a purchase price equal to 100% of the principal amount together with accrued interest, plus a make-whole amount determined in accordance with the master shelf agreement. The senior secured notes issued 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance. During 2008 the notes may also incur an additional fee each quarter of 0.15% per annum on the outstanding borrowings if the Partnership's leverage ratio, as defined in the agreement, exceeds certain levels during such quarterly period.

The master shelf agreement relating to the notes contains substantially the same covenants and events of default as the bank credit facility.

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

The Partnership was in compliance with all debt covenants at December 31, 2007 and 2006 and expects to be in compliance with debt covenants for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement, the lenders under the bank credit facility and the purchasers of the senior secured notes have entered into an Intercreditor and Collateral Agency Agreement, which has been acknowledged and agreed to by the Partnership and its subsidiaries. This agreement appointed Bank of America, N.A. to act as collateral agent and authorized Bank of America to execute various security documents on behalf of the lenders under the bank credit facility and the purchasers of the senior secured notes. This agreement specifies various rights and obligations of lenders under the bank credit facility, holders of senior secured notes and the other parties thereto in respect of the collateral securing the Partnership's obligations under the bank credit facility and the master shelf agreement.

Other Note Payable. In June 2002, as part of the purchase price of Florida Gas Transmission Company (FGTC), the Partnership issued a note payable for $0.8 million to FGTC payable in $0.1 million annual increments through June 2006 with the final payment of $0.6 million paid in June 2007.

Maturities. Maturities for the long-term debt as of December 31, 2007 are as follows (in thousands):

2008	$	9,412
2009		9,412
2010		20,294
2011		766,000
2012		93,000
Thereafter		325,000

(6) Other Long-Term Liabilities

In November 2007, the Partnership entered into a 10-year capital lease for certain compressor equipment. Assets under capital leases as of December 31, 2007 are summarized as follows (in thousands):

Compressor equipment	$	4,011
Less: Accumulated amortization		(29)
Net assets under capital lease	$	3,982

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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, 2007 (in thousands):

Fiscal Year	
2008 through 2012 ($445 annually)	$ 2,225
Thereafter	2,743
Less: Interest	(980)
Net minimum lease payments under capital lease	3,988
Less: Current portion of net minimum lease payments	(435)
Long-term portion of net minimum lease payments	$ 3,553

(7) Partners' Capital

(a) Issuance of Common Units, Senior Subordinated Units, Senior Subordinated Series C Units and Senior Subordinated Series D Units

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

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 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 will 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 will automatically convert into common units representing limited partner interests of the Partnership on March 23, 2009 at a ratio of one common unit for each senior subordinated series D unit, subject to adjustment depending on the achievement of financial metrics in the fourth quarter of 2008. The senior subordinated series D units are not entitled to distributions of available cash or allocation of net income/loss from the Partnership until March 23, 2009.

On June 24, 2005, the Partnership issued 1,495,410 senior subordinated units (herein referred to as "senior subordinated A units") in a private equity offering for net proceeds of $51.1 million, including Crosstex Energy GP, L.P.'s general partner capital contribution of $1.1 million. The senior subordinated units were issued at $33.44 per unit, which represented a discount of 13.7% to the market value of common units on such date, and automatically converted to common units on a one-for-one basis on February 24, 2006. The senior subordinated units received no distributions until their conversion to common units.

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 15, 2008. The senior subordinated series C units were not entitled to distributions of available cash from the Partnership until conversion.

(b) Subordination Period

The subordination period for the Partnership's subordinated units (excluding all senior subordinated units) ended on December 31, 2007 and the remaining 4,668,000 subordinated units converted into common units effective February 16, 2008.

The Partnership met the applicable financial tests in the Partnership Agreement for the three consecutive four-quarter periods ending on December 31, 2005 and 2006, therefore 4,666,000 of the subordinated units were converted into common units prior to December 31, 2007. The Partnership met the financial tests for three consecutive four-quarter periods ended December 31, 2007, so the remaining 4,668,000 subordinated units converted to common units upon the payment of the fourth quarter distribution on February 15, 2008.

(c) Cash Distributions

In accordance with the partnership agreement, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter commencing with the quarter ended on March 31, 2003. Distributions will generally be made 98% to the common and subordinated unit-holders and 2% to the general partner, subject to the payment of incentive distributions as described below to the extent that certain target levels of cash distributions are achieved. The Partnership's senior secured credit facility prohibits the Partnership from declaring distributions to unitholders if any event of default exists or would result from the declaration of distributions. See Note (5) for a description of the bank credit facility covenants.

Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $24.8 million, $20.4 million and $10.7 million were earned by our general partner for the years ended December 31, 2007, 2006 and 2005, respectively. The Partnership paid annual per common unit distributions of $2.28, $2.18 and $1.93 for the years ended December 31, 2007, 2006 and 2005, respectively.

The Partnership increased its fourth quarter distribution on its common and subordinated units to $0.61 per unit which was paid on February 15, 2008.

(d) Earnings per unit and anti-dilutive computations

The Partnership's common units and subordinated units participate in earnings and distributions in the same manner for all historical periods and are therefore presented as a single class of common units for earnings per unit computations. The various series of senior subordinated units are also considered common securities, but because they do not participate in earnings or cash distributions during the subordination period are presented as separate classes of common equity. Each of the series of senior subordinated units were issued at a discount to the market price of the common units they are convertible into at the end of the subordination period. These discounts represent beneficial conversion features (BCFs) under EITF 98-5: *"Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios."* Under EITF 98-5 and related accounting guidance, a BCF represents a non- cash distribution that is treated in the same way as a cash distribution for earnings per unit computations. Since the conversion of all the series of senior subordinated units into common units are contingent (as described with the terms of such units) until the end of the subordination periods for each series of units, the BCF associated with each series of senior subordinated units is not reflected in earnings per unit until the

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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 2005, 2006 and 2007 (in thousands):

	BCF	End of Subordination Period
Senior subordinated A units	$ 7,941	February 2006
Senior subordinated series C units	$ 121,112	February 2008
Senior subordinated series D units	$ 34,297	March 2009

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

	Years Ended December 31, 2007	2006	2005
Limited partners' interest in net income (loss)	$ (5,363)	$ (20,647)	$ 10,548
Distributed earnings allocated to:			
Common units(1)	$ 61,760	$ 55,827	$ 33,914
Senior subordinated A units(2)	—	7,941	—
Total distributed earnings	$ 61,760	$ 63,768	$ 33,914
Undistributed loss allocated to:			
Common units(3)	$ (67,123)	$ (84,415)	$ (23,366)
Senior subordinated A units	—	—	—
Total undistributed earnings (loss)	$ (67,123)	$ (84,415)	$ (23,366)
Net income (loss) allocated to:			
Common units	$ (5,363)	$ (20,647)	$ 10,548
Senior subordinated A units	—	7,941	—
Total limited partners' interest in net income (loss)	$ (5,363)	$ (12,706)	$ 10,548
Cumulative effect of the change in accounting principle:			
Common units	$ —	$ 689	$ —
Senior subordinated A, C and D units	—	—	—
Total cumulative effect of the change in accounting principle	$ —	$ 689	$ —
Basic net income (loss) per common unit before cumulative effect of change in accounting principle:	$ (0.20)	$ (1.12)	$ 0.56

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

	Years Ended December 31, 2007	2006	2005
Dulited net income (loss) per common unit before cumulative effect of change in accounting principle	$ (0.20)	$ (1.12)	$ 0.51
Senior subordinated A units	$ —	$ 5.31	$ —
Senior subordinated series C and D units	$ —	$ —	$ —
Basic cumulative effect of change in accounting principle per unit:			
Common units	$ —	$ 0.03	$ —
Senior subordinated A, C and D units	$ —	$ —	$ —
Basic net income (loss) per common unit	$ (0.20)	$ (1.09)	$ 0.56
Diluted net income (loss) per common unit	$ (0.20)	$ (1.09)	$ 0.51
Senior subordinated A units	$ —	$ 5.31	$ —
Senior subordinated series C and D units	$ —	$ —	$ —

(1) Represents distributions paid to common and subordinated unitholders.

(2) Represents BCF recognized at end of subordination period for senior subordinated A units.

(3) All undistributed earnings and losses are allocated to common units during the subordination period.

The following are the unit amounts used to compute the basic and diluted earnings per limited partner unit for the years ended December 31, 2007, 2006, and 2005 (in thousands, except per-unit amounts):

	Years Ended December 31, 2007	2006	2005
Basic earnings per unit:			
Weighted average limited partner units outstanding	26,753	26,337	19,006
Dilutive earnings per unit:			
Weighted average limited partner units outstanding	26,753	26,337	19,006
Dilutive effect of restricted units	—	—	162
Dilutive effect of senior subordinated units	—	—	773
Dilutive effect of exercise of options outstanding	—	—	586
Dilutive units	26,753	26,337	20,527

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, 2007 and 2006 because the limited partners were allocated net losses in the periods.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note 7(c). In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to CEI stock options and restricted stock all to the general partner to match the related general partner contribution. Therefore, the general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units and the common units. The net income allocated to the general partner is as follows (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Income allocation for incentive distributions	$ 24,802	$ 20,422	$ 10,660
Stock-based compensation attributable to CEI's stock options and restricted shares	(5,441)	(3,545)	(2,223)
2% general partner interest in net income (loss)	(109)	(421)	215
General partner share of net income	$ 19,252	$ 16,456	$ 8,652

(8) 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 $1.6 million, $1.1 million and $0.6 million were made to the plan for the years ended December 31, 2007, 2006 and 2005, respectively.

(9) Employee Incentive Plans

(a) Long-Term Incentive Plan

The Partnership's managing general partner has a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 4,800,000 common unit options and restricted units. The plan is administered by the compensation committee of the managing general partner's board of directors. The units issued upon exercise or vesting are newly issued units.

(b) Restricted Units

A restricted unit is a "phantom" unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the compensation committee, cash equivalent to the value of a common unit. In addition, the restricted units will become exercisable upon a change of control of the Partnership, its general partner or its general partner's general partner.

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted in 2005, 2006 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, 2007 is provided below:

	Number of Units	Weighted Average Grant-Date Fair Value
Crosstex Energy, L.P. Restricted Units:		
Non-vested, beginning of period	336,504	$ 32.01
Granted	224,262	35.26
Vested	(38,052)	23.33
Forfeited	(18,196)	26.99
Non-vested, end of period	504,518	$ 34.29
Aggregate intrinsic value, end of period (in thousands)	$ 15,650	

In July 2007, the Partnership's executive officers were granted restricted units based on the accomplishment of certain performance targets. The target number of restricted units for all executives of 47,742 will be increased (up to a maximum of 200% of the target number of units) or decreased (to a minimum of 30% of the target number of units) based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over the three-year period from January 2007 through January 2010) compared to the Partnership's target average growth rate of 10.5%. The restricted unit activity for the period ended December 31, 2007 reflects 47,742 performance-based restricted unit grants for executive officers based on current performance models. The performance-based restricted units are included in the current share-based compensation calculations as required by SFAS No. 123(R) when it is deemed probable of achieving the performance criteria. All performance-based awards greater than the minimum performance grants will be subject to reevaluation and adjustment until the restricted units vest in January 2010.

The aggregate intrinsic value of vested units during the years ended December 31, 2007 and 2006 was $1.3 million and $0.7 million, respectively. The fair value of units vested during the years ended December 31, 2007 and 2006 was $0.9 million and $0.3 million, respectively. As of December 31, 2007, there was $6.8 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.3 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. 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 contractual term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant.

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, although a substantial portion of the unit options granted during 2005 were granted during the second quarter of the year with an exercise price equal to the market price at the beginning of the fiscal year, resulting in an exercise price that was less than the market price at grant. In accordance with APB No. 25, compensation expense was recorded during 2005 to the extent the market value of the unit exceeded the exercise price of the unit option at the measurement date. The unit options granted in 2007, 2006 and 2005 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 2007, 2006 and 2005:

	Years Ended December 31, 2007	2006	2005
Crosstex Energy, L.P. Unit Options Granted:			
Weighted average distribution yield	5.75%	5.5%	5.5%
Weighted average expected volatility	32.0%	33.0%	33.0%
Weighted average risk free interest rate	4.39%	4.80%	3.83%
Weighted average expected life	6 years	6 years	5.0 years
Weighted average contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$6.73	$7.45	$8.42

A summary of the unit option activity for the years ended December 31, 2007, 2006 and 2005 is provided below:

	Years Ended December 31, 2007 Number of Units	2007 Weighted Average Exercise Price	2006 Number of Units	2006 Weighted Average Exercise Price	2005 Number of Units	2005 Weighted Average Exercise Price
Outstanding, beginning of period	926,156	$ 25.70	1,039,832	$ 18.88	1,043,865	$ 15.58
Granted	347,599	37.29	286,403	34.62	193,511	32.78
Exercised	(90,032)	18.20	(304,936)	11.19	(127,097)	10.57
Forfeited	(67,688)	29.84	(95,143)	24.56	(70,447)	23.15
Expired	(8,726)	31.60	—	—	—	—
Outstanding, end of period	1,107,309	$ 29.65	926,156	$ 25.70	1,039,832	$ 18.88
Options exercisable at end of period	281,973	$ 28.05	121,131	$ 23.58	308,455	$ 11.34
Weighted average contractual term (years) end of period:						
Options outstanding	7.6	—	7.8	—	—	—
Options exercisable	7.1	—	7.5	—	—	—
Aggregate intrinsic value end of period (in thousands):						
Options outstanding	$ 4,681	—	$ 13,107	—	—	—
Options exercisable	$ 1,322	—	$ 1,970	—	—	—
Weighted average fair value of options granted with an exercise price equal to market price at grant	(a)	(a)	(a)	(a)	—	—
Weighted average fair value of options granted with an exercise price less than market price at grant	(a)	(a)	(a)	(a)	193,511	$ 8.42

(a) Disclosure not required under FAS No. 123R. No options were granted with an exercise price less than market value at grant during 2007 and 2006.

The total intrinsic value of unit options exercised during the years ended December 31, 2007 and 2006 was $1.7 million and $7.6 million, respectively. The fair value of unit options vested during the years ended December 31, 2007 and 2006 was $0.2 million. As of December 31, 2007, there was $2.4 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 1.6 years.

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

The Crosstex Energy, Inc. long-term incentive plan provides for the award of stock options and restricted stock (collectively, "Awards") for up to 4,590,000 shares of Crosstex Energy, Inc.'s common stock. As of January 1, 2008, approximately 924,533 shares remained available under the long-term incentive plan for future issuance to participants.

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 2005, 2006 and 2007 generally cliff vest after three years of service. A summary of the restricted stock activity for the year ended December 31, 2007 is provided below:

	Number of Shares	Weighted Average Grant-Date Fair Value
Crosstex Energy, Inc. Restricted Shares:		
Non-vested, beginning of period	751,749	$ 17.03
Granted	244,578	29.58
Vested	(90,156)	14.14
Forfeited	(45,896)	14.32
Non-vested, end of period	860,275	$ 21.16
Aggregate intrinsic value, end of period (in thousands)	$ 32,037	

In July 2007, the Partnership's executive officers were granted restricted shares based on the accomplishment of certain performance targets. The target number of restricted shares for all executives of 55,131 will be increased (up to a maximum of 200% of the target number of units) or decreased (to a minimum of 30% of the target number of units) based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over the three-year period from January 2007 through January 2010) compared to the Partnership's target average growth rate of 10.5%. The restricted share activity for the period ended December 31, 2007 reflects 55,131 performance-based restricted share grants for executive officers based on current performance models. The performance-based restricted shares are included in the current share-based compensation calculations as required by SFAS No. 123(R) when it is deemed probable of achieving the performance criteria. All performance-based awards greater than the minimum performance grants will be subject to reevaluation and adjustment until the restricted shares vest in January 2010.

Restricted shares in CEI totaling 186,840 and 404,640 were issued to officers and employees of the Partnership with a weighted-average grant-date fair value of $25.05 and $16.73 per share in 2006 and 2005, respectively. As of December 31, 2007 and 2006, there was $7.0 million and $6.7 million, respectively, of unrecognized compensation costs related to CEI restricted shares for officers and employees.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

The aggregate intrinsic value and the fair value of vested shares for the year ended December 31, 2007 was $3.1 million $1.3 million, respectively. No shares vested for the year ended December 31, 2006.

No CEI stock options were granted to any officers or employees of the Partnership during 2007, 2006 and 2005.

A summary of the stock option activity for the years ended December 31, 2007, 2006 and 2005 is provided below:

	Years Ended December 31,					
	2007		2006		2005	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares(a)	Weighted Average Exercise Price(a)
Outstanding, beginning of period	120,000	$ 8.21	159,933	$ 9.53	2,161,152	$ 2.22
Granted	—	—	—	—	68,958	13.85
Cancelled	—	—	—	—	(27,060)	15.23
Exercised	(15,000)	6.50	(9,933)	12.58	(2,043,117)	1.87
Forfeited	—	—	(30,000)	13.83	—	—
Outstanding, end of period	105,000	$ 8.45	120,000	$ 8.21	159,933	$ 9.53
Options exercisable at end of period	37,500	$ 7.87	—	—	9,933	$ 12.58
Weighted average fair value of options granted with an exercise price equal to market price at grant(a)	(b)	(b)	(b)	(b)	68,958	$ 3.68
Weighted average fair value of options granted with an exercise price less than market at grant(a)	(b)	(b)	(b)	(b)	—	—

(a) Adjusted to reflect three-for-one stock split.

(b) Disclosure not required under FAS No. 123R. No options were granted during 2007 and 2006.

The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of December 31, 2007:

Outstanding stock options (non exercisable) (post stock split)	30,000
Weighted average exercise price (post stock split)	$ 13.33
Aggregate intrinsic value	$ 717,200
Weighted average remaining contractual term	6.9 years

The total intrinsic value of CEI stock options exercised by officers and employees of the Partnership during the year ended December 31, 2005 was $27.0 million. The aggregate intrinsic value of exercised units during the years ended December 31, 2007 and 2006 was $0.4 million and $0.1 million, respectively. The fair value of shares vested during the years ended December 31, 2007 and 2006 was less than $0.1 million each year. No stock options were granted, cancelled, exercised or forfeited by officers and employees of the Partnership during the years ended December 31, 2006 and 2005.

As of December 31, 2007, there was $36,000 of unrecognized compensation costs related to non-vested CEI stock options. The cost is expected to be recognized over a weighted average period of 1.8 years.

(10) 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).

	2007		2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 142	$ 142	$ 824	$ 824
Trade accounts receivable and accrued revenues	489,889	489,889	367,023	367,023
Fair value of derivative assets	9,926	9,926	26,860	26,860
Note receivable	1,026	1,026	926	926
Accounts payable, drafts payable and accrued gas purchases	469,951	469,951	404,863	404,863
Current portion of long-term debt	9,412	9,412	10,012	10,012
Long-term debt	1,213,706	1,225,087	977,118	981,914
Fair value of derivative liabilities	30,492	30,492	14,699	14,699

The carrying amounts of the Partnership's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities. The carrying value for the note receivable approximates the fair value because this note earns interest based on the current prime rate.

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $734.0 million and $488.0 million as of December 31, 2007 and 2006, 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, 2007, the Partnership also had borrowings totaling $489.1 million under senior secured notes with a weighted average interest rate of 6.75%. The fair value of these borrowings as of December 31, 2007 and 2006 were adjusted to reflect to current market interest rate for such borrowings as of December 31, 2007 and 2006, 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.

(11) Derivatives

Interest Rate Swaps

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk.

The Partnership has entered into eight interest rate swaps as of December 31, 2007 as shown below:

Trade Date	Term	From	To	Rate	Notional Amounts (In thousands):
November 14, 2006	3 years	November 28, 2006	November 30, 2009	4.950%	$ 50,000
March 13, 2007	3 years	March 30, 2007	March 31, 2010	4.875%	$ 50,000
July 30, 2007	3 years	August 30, 2007	August 30, 2010	5.070%	$ 100,000
August 6, 2007	3 years	August 30, 2007	August 30, 2010	4.970%	$ 50,000
August 9, 2007	2 years	November 30, 2007	November 30, 2009	4.950%	$ 50,000
August 16, 2007	3 years	October 31, 2007	October 31, 2010	4.775%	$ 50,000
September 5, 2007	3 years	September 28, 2007	September 30, 2010	4.700%	$ 50,000
September 11, 2007	3 years	October 31, 2007	October 31, 2010	4.540%	$ 50,000
					$ 450,000

Each swap fixes the three month LIBOR rate, prior to credit margin, at the indicated rates for the specified amounts of related debt outstanding over the term of each swap agreement. The Partnership has elected to designate all interest rate swaps (except the November 2006 swap) as cash flow hedges for FAS 133 accounting treatment. Accordingly, unrealized gains and losses relating to the designated interest rate swaps are recorded in accumulated other comprehensive income until the related interest rate expense is recognized in earnings. Unrealized gains and losses relating to the November 2006 interest rate swap are recorded through the consolidated statement of operations in (gain)/loss on derivatives over the period hedged.

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

	Year Ended December 31, 2007
Change in fair value of derivatives that do not qualify for hedge accounting	$ 1,185
Realized gains on derivatives	(234)
Ineffective portion of derivatives qualifying for hedge accounting	—
	$ 951

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

There is no ineffectiveness related to the interest rate swaps that qualify for hedge accounting.

No comparison is listed for 2005 or 2006 because the first interest rate swaps were entered into in November 2006 and therefore had no material operational impact prior to 2007.

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

	Years Ended December 31, 2007	2006
Fair value of derivative assets — current	$ 68	$ 89
Fair value of derivative assets — long-term	—	—
Fair value of derivative liabilities — current	(3,266)	—
Fair value of derivative liabilities — long-term	(8,057)	—
Net fair value of derivatives	$ (11,255)	$ 89

At December 31, 2007, an unrealized loss of $10.2 million was recorded in accumulated other comprehensive income related to the interest rate swaps. Due to the decline in interest rates in January 2008, the Partnership revised the interest rate swaps to take advantage of the rate decline. The interest rate swaps were de-designated at that time and the Partnership will recognize the amounts in accumulated other comprehensive income in current earnings as the swaps mature. Subsequent changes in fair value of the swaps will be recorded in current earnings.

Commodity Swaps

The Partnership manages its exposure to fluctuations in commodity prices by hedging the impact of market fluctuations. Swaps are used to manage and hedge prices and location risk related to these market exposures. Swaps are also used to manage margins on offsetting fixed-price purchase or sale commitments for physical quantities of natural gas and NGLs.

The Partnership commonly enters into various derivative financial transactions which it does not designate as hedges. These transactions include “swing swaps”, “third party on-system financial swaps”, “marketing financial swaps”, “storage swaps”, “basis swaps” and “processing margin swaps”. Swing swaps are generally short-term in nature (one month), and are usually entered into to protect against changes in the volume of daily versus first-of-month index priced gas supplies or markets. Third party on-system financial swaps are hedges that the Partnership enters into on behalf of its customers who are connected to its systems, wherein the Partnership fixes a supply or market price for a period of time for its customers, and simultaneously enters into the derivative transaction. Marketing financial swaps are similar to on-system financial swaps, but are entered into for customers not connected to the Partnership’s systems. Storage swaps transactions protect against changes in the value of gas that the Partnership has stored to serve various operational requirements. Basis swaps are used to hedge basis location price risk due to buying gas into one of our systems on one index and selling gas off that same system on a different index. Processing margin financial swaps are used to hedge frac spread risk at our processing plants relating to the option to process versus bypassing our equity gas.

In August 2005 the Partnership acquired puts, or rights to sell a portion of the liquids from the plants at a fixed price over a two-year period beginning January 1, 2006 for a premium of $18.7 million as part of the overall risk management plan related to the acquisition of the El Paso assets which closed on November 1, 2005. The Partnership sold a portion of these puts in December 2005 and in January 2007 for $4.3 million and $0.8 million, respectively. The Partnership did not designate these put options to obtain hedge accounting and therefore, these put options were marked to market through our consolidated statements of operations for the years ended December 31, 2005, 2006 and 2007. The puts represented options, but not obligations, to sell the related underlying liquids volumes at a fixed price. As of December 31, 2007, all the put options have expired.

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

	December 31, 2007	December 31, 2006	December 31, 2005
Change in fair value of derivatives that do not qualify for hedge accounting	$ 1,197	$ 713	$ 10,169
Realized (gains) losses on derivatives	(7,918)	(2,238)	(240)
Ineffective portion of derivatives qualifying for hedge accounting	104	(74)	39
	$ (6,617)	$ (1,599)	$ 9,968

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

	December 31, 2007	December 31, 2006
Fair value of derivative assets — current	$ 8,521	$ 22,959
Fair value of derivative assets — long term	1,337	3,812
Fair value of derivative liabilities — current	(17,800)	(12,141)
Fair value of derivative liabilities — long term	(1,369)	(2,558)
Net fair value of derivatives	$ (9,311)	$ 12,072

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, 2007 (all gas volumes are expressed in MMBtu's and liquids are expressed in gallons). The remaining terms of the contracts extend no later than June 2010 for derivatives. The Partnership's counterparties to derivative contracts include BP Corporation, Total Gas & Power, Fortis, UBS Energy, Morgan Stanley, J. Aron & Co., a subsidiary of Goldman Sachs and Sempra Energy. Changes in the fair value of the Partnership's mark to market derivatives are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings. The ineffective portion is recorded in earnings immediately.

Transaction Type	December 31, 2007 Volume	Fair Value
	(In thousands)	
Cash Flow Hedges:		
Natural gas swaps (short contracts) (MMBtu's)	(2,574)	$ 1,703
Liquids swaps (long contracts) (gallons)	2,452	1,352
Liquids swaps (short contracts) (gallons)	(33,396)	(14,377)
Total swaps designated as cash flow hedges		$ (11,322)
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	908	$ (8)
Physical offsets to swing swap transactions (short contracts)	(908)	—
Swing swaps (short contracts)	(2,285)	3
Physical offsets to swing swap transactions (long contracts)	2,285	—
Basis swaps (long contracts)	36,700	1,449
Physical offsets to basis swap transactions (short contracts)	(3,570)	26,283
Basis swaps (short contracts)	(31,825)	(1,191)
Physical offsets to basis swap transactions (long contracts)	5,555	(25,117)
Third-party on-system financial swaps (long contracts)	4,551	(958)
Physical offsets to third-party on-system transactions (short contracts)	(4,551)	1,299
Third-party on-system financial swaps (short contracts)	(114)	81
Physical offsets to third-party on-system transactions (long contracts)	114	(74)
Third-party off-system financial swaps (short contracts)	(915)	259
Physical offsets to third-party off-system transactions (long contracts)	915	(195)
Storage swap transactions (long contracts)	150	(85)
Storage swap transactions (short contracts)	(413)	265
Total mark to market derivatives		$ 2,011

* All are gas contracts, volume in MMBtu's

On all transactions where the Partnership is exposed to counterparty risk, the Partnership analyzes the counterparty's financial condition prior to entering into an agreement, establishes limits, and monitors the appropriateness of these limits on an ongoing basis.

Impact of Cash Flow Hedges

Natural Gas

For the year ended December 31, 2007, net gains on natural gas cash flow hedge contracts increased gas revenue by $5.5 million. For the year ended December 31, 2006, net gains on natural gas cash flow hedge contracts increased gas revenue by $5.9 million. As of December 31, 2007, an unrealized pre-tax derivative fair value net gain of $1.7 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income. Of this net amount, $2.0 million is expected to be reclassified into earnings through December 2008. 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.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

The settlement of natural gas cash flow agreements related to January 2008 gas production increased gas revenue by approximately $0.6 million.

Liquids

For the year ended December 31, 2007, net losses on liquids swap hedge contracts decreased liquids revenue by approximately $4.1 million. For the year ended December 31, 2006, net gains on liquids swap hedge contracts increased liquids revenue by approximately $1.5 million. For the year ended December 31, 2007, an unrealized pre-tax derivative fair value loss of $12.9 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income. Of this amount, $12.8 million is expected to be reclassified into earnings through December 2008. 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, puts, 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, 2007	$ 1,570	$ 344	$ 97	$ 2,011

(12) Transactions with Related Parties

(a) Treating Fees and Gas Purchases

The Partnership treats gas for, and purchases gas from, Camden Resources, Inc. (Camden) and treats gas for Erskine Energy Corporation (Erskine) and Approach Resources, Inc. (Approach). All three entities are affiliates of the Partnership by way of equity investments made by Yorktown Energy Partners, IV, L.P. and Yorktown Energy Partners V, L.P., in Camden, Erskine and Approach. A director of both CEI and the Partnership is a founder and senior manager of Yorktown Partners LLC, the manager of the Yorktown group of investment partnerships.

The table below lists related party transactions (in thousands):

	Years Ended December 31,		
	2007	2006	2005
Treating Fees			
Camden	$ 2,140	$ 2,612	$ 2,621
Erskine	850	1,289	—
Approach	—	279	—
Gas Purchases			
Camden	$ 22,650	$ 32,485	$ 67,231

(b) General and Administrative Expenses

CEI paid the Partnership $0.6 million, $0.5 million and $0.3 million during the years ended December 31, 2007, 2006 and 2005, respectively, to cover its portion of administrative and compensation costs for officers and employees that perform services for CEI.

(13) Commitments and Contingencies

(a) Leases — Lessee

We have operating leases for office space, office and field equipment and the Eunice plant. The Eunice plant operating lease acquired with the south Louisiana processing assets provides for annual lease payments of $12.2 million with a lease term extending to November 2012. At the end of the lease term we have the option to purchase the plant for $66.3 million or to renew the lease for up to an additional 9.5 years at 50% of the lease payments under the current lease.

The following table summarizes our remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in millions):

2008	$ 24.7
2009	21.4
2010	18.4
2011	17.3
2012	16.3
Thereafter	6.8
	$ 104.9

Operating lease rental expense in the years ended December 31, 2007, 2006 and 2005, was approximately $31.7 million, $23.8 million, and $6.6 million, respectively.

(b) Leases — Lessor

During 2007, the Partnership leased approximately 159 of its treating plants and 33 of its dew point control plants to customers under operating leases. The initial terms on these leases are generally 12 months, at which time the leases revert to 30-day cancelable leases. As of December 31, 2007, the Partnership only had 20 treating plants under 24 operating leases with remaining non-cancelable lease terms in excess of one year. The future minimum lease rentals are $8.3 million and $5.5 million for the years ended December 31, 2008 and 2009, respectively. These leased treating plants have a cost of $21.8 million and accumulated depreciation of $4.7 million as of December 31, 2007.

(c) Employment Agreements

Certain members of management of the Partnership are parties to employment contacts with the general partner. The employment agreements provide those senior managers with severance payments in certain circumstances and prohibit each such person from competing with the general partner or its affiliates for a certain period of time following the termination of such person's employment.

(d) Environmental Issues

The Partnership acquired the south Louisiana processing assets from the El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that will drastically reduce the remediation time as well as the costs associated with such remediation projects. As of December 31, 2007, we had incurred approximately $0.5 million in such remediation costs, of which $0.4 million had already been paid. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

The Partnership acquired LIG Pipeline Company and its subsidiaries on April 1, 2004. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. The seller, AEP, has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third-party company pursuant to which the remediation costs associated with these sites have been assumed by this third-party company that specializes in remediation work. The Partnership does not expect to incur any material liability with these sites. In addition, the Partnership has disclosed possible Clean Air Act monitoring deficiencies it has discovered to the Louisiana Department of Environmental Quality and is working with the department to correct these deficiencies and to address modifications to facilities to bring them into compliance. The Partnership does not expect to incur any material environmental liability associated with these issues.

The Partnership acquired assets from Duke Energy Field Services, or DEFS, in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The estimated remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of the Conroe site. Moreover, a third-party company has assumed the remediation costs associated with the Conroe site. Therefore, the Partnership does not expect to incur any material environmental liability associated with the Conroe site.

(e) Other

The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

On November 15, 2007, Crosstex CCNG Processing Ltd. (Crosstex CCNG), our wholly-owned subsidiary, received a demand letter from Denbury Onshore, LLC (Denbury), asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. The claim arises from a contract under which Crosstex CCNG processed natural gas owned or controlled by Denbury in north Texas. Denbury contends that Crosstex CCNG breached the contract by failing to build a processing plant of a certain size and design, resulting in Crosstex CCNG's failure to properly process the gas over a ten month period. Denbury also alleges that Crosstex CCNG failed to provide specific notices required under the contract. On December 4, 2007, and again on February 14, 2008, Denbury sent Crosstex CCNG letters demanding that its claim be arbitrated pursuant to an arbitration provision in the contract. Denbury subsequently requested that the parties attempt to mediate the matter before any arbitration proceeding is initiated. Although it is not possible to predict with certainty the ultimate outcome of this matter, we do not believe this will have a material adverse impact on our consolidated results of operations or financial position.

(14) Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Partnership's reportable segments consist of Midstream and Treating. The Midstream division consists of the Partnership's natural gas gathering and transmission operations and includes the south Louisiana processing and liquids assets, the processing and transmission assets located in north and south Texas, the LIG pipelines and processing plants located in Louisiana, the Mississippi System, the Arkoma system in Oklahoma and various other small systems. Also included in the Midstream division are the Partnership's energy trading operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or through fixed monthly payments. The Seminole carbon dioxide processing plant located in Gaines County, Texas is included in the Treating division.

The accounting policies of the operating segments are the same as those described in Note 2 of the Notes to Consolidated Financial Statements. The Partnership evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include general partnership expenses associated with managing all reportable operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt financing costs.

CROSSTEX ENERGY, L.P.

Notes to Consolidated Financial Statements — (Continued)

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

	Midstream	Treating	Corporate	Totals
		(In thousands)		
Year ended December 31, 2007:				
Sales to external customers	$ 3,791,316	$ 65,025	$ —	$ 3,856,341
Profit on energy trading activities	4,090	—	—	4,090
Purchased gas	(3,468,924)	(7,892)	—	(3,476,816)
Operating expenses	(104,930)	(22,829)	—	(127,759)
Segment profit	$ 221,552	$ 34,304	$ —	$ 255,856
Inter-segment sales	$ 14,386	$ (14,386)	$ —	$ —
Gain (loss) on derivatives	$ 6,628	$ (11)	$ (951)	$ 5,666
Depreciation and amortization	$ (89,575)	$ (14,568)	$ (4,737)	$ (108,880)
Capital expenditures (excluding acquisitions)	$ 371,120	$ 25,085	$ 5,192	$ 401,397
Identifiable assets	$ 2,337,081	$ 214,481	$ 41,312	$ 2,592,874
Year ended December 31, 2006:				
Sales to external customers	$ 3,075,481	$ 63,813	$ —	$ 3,139,294
Profit on energy trading activities	2,510	—	—	2,510
Purchased gas	(2,859,815)	(9,463)	—	(2,869,278)
Operating expenses	(80,943)	(20,048)	—	(100,991)
Segment profit	$ 137,233	$ 34,302	$ —	$ 171,535
Inter-segment sales	$ 12,932	$ (12,932)	$ —	$ —
Gain (loss) on derivatives	$ 1,591	$ 8	$ —	$ 1,599
Depreciation and amortization	$ (63,348)	$ (15,800)	$ (3,583)	$ (82,731)
Capital expenditures (excluding acquisitions)	$ 294,597	$ 31,463	$ 8,184	$ 334,244
Identifiable assets	$ 1,960,213	$ 203,528	$ 30,733	$ 2,194,474
Year ended December 31, 2005:				
Sales to external customers	$ 2,982,874	$ 48,606	$ —	$ 3,031,480
Profit on energy trading activities	1,568	—	—	1,568
Purchased gas	(2,860,823)	(9,706)	—	(2,870,529)
Operating expenses	(41,965)	(14,771)	—	(56,736)
Segment profit	$ 81,654	$ 24,129	$ —	$ 105,783
Inter-segment sales	$ 10,003	$ (10,003)	$ —	$ —
Gain (loss) on derivatives(a)	$ (9,968)	$ —	$ —	$ (9,968)
Depreciation and amortization	$ (23,243)	$ (10,646)	$ (2,135)	$ (36,024)
Capital expenditures (excluding acquisitions)	$ 98,284	$ 22,886	$ 6,512	$ 127,682
Identifiable assets	$ 1,278,017	$ 130,435	$ 16,706	$ 1,425,158

(a) Midstream segment profit is net of non-cash derivative loss of $10.2 million.

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

	Years Ended December 31, 2007	2006	2005
Segment profits	$ 255,856	$ 171,535	$ 105,783
General and administrative expenses	(61,528)	(45,694)	(32,697)
Gain (loss) on derivatives	5,666	1,599	(9,968)
Gain (loss) on sale of property	1,667	2,108	8,138
Depreciation and amortization	(108,880)	(82,731)	(36,024)
Operating income	$ 92,781	$ 46,817	$ 35,232

(15) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
			(In thousands, except per unit data)		
2007					
Revenues	$ 826,752	$ 1,001,916	$ 943,269	$ 1,088,494	$ 3,860,431
Operating income	12,224	21,535	22,983	36,039	92,781
Net income (loss)	(5,277)	2,888	2,130	14,148	13,889
Earnings (loss) per limited partner unit-basic	$ (0.36)	$ (0.06)	$ (0.10)	$ 0.31	$ (0.20)
Earnings (loss) per limited partner unit-diluted	$ (0.36)	$ (0.06)	$ (0.10)	$ 0.19	$ (0.20)
Basic and diluted senior subordinated A unit:	$ —	$ —	$ —	$ —	$ —
2006					
Revenues	$ 817,119	$ 744,655	$ 855,285	$ 724,745	$ 3,141,804
Operating income	9,975	9,997	16,271	10,574	46,817
Net income (loss)	2,040	(2,259)	903	(4,875)	(4,191)
Earnings (loss) per limited partner unit — basic	$ (0.39)	$ (0.23)	$ (0.12)	$ (0.34)	$ (1.09)
Earnings (loss) per limited partner unit — diluted	$ (0.39)	$ (0.23)	$ (0.12)	$ (0.34)	$ (1.09)
Basic and diluted senior subordinated A unit:	$ 5.31	$ —	$ —	$ —	$ 5.31

(16) Condensed Consolidating Financial Statements

In connection with the Partnership's filing of a shelf registration statement on Form S-3 with the Securities and Exchange Commission (the "Registration Statement"), all of the Partnership's wholly-owned subsidiaries, excluding minor subsidiaries, may issue unconditional guarantees of senior or subordinated debt securities of the Partnership in the event that the Partnership issues such securities from time to time under the Registration Statement. If issued, the guarantees will be full, irrevocable and unconditional. The Partnership does not provide separate financial statements of such subsidiaries because the Partnership has no independent assets or operations, the guarantees are full and unconditional and the non-guarantor subsidiaries are minor. There are no significant restrictions on the ability of the Partnership to obtain funds from any of its subsidiaries by dividend or loan.

Schedule II

CROSSTEX ENERGY, L.P.

VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In thousands)		
Year ended December 31, 2007				
Allowance for doubtful accounts	$ 618	$ 367	—	$ 985
Year ended December 31, 2006				
Allowance for doubtful accounts	$ 259	$ 359	—	$ 618
Year ended December 31, 2005				
Allowance for doubtful accounts	$ 59	$ 200	—	$ 259

EXHIBIT INDEX

Number		Description
3.1	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1, file No. 333-97779).
3.2	—	Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated as of March 23, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
3.3	—	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Crosstex Energy, L.P., dated December 20, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated December 20, 2007, filed with the Commission on December 21, 2007).
3.4	—	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).
3.5	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference to Exhibit 3.5 to our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.6	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference to Exhibit 3.5 to our Registration Statement on Form S-1, file No. 333-97779).
3.7	—	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).
3.8	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference to Exhibit 3.7 to our Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference to Exhibit 3.8 to our Registration Statement on Form S-1, file No. 333-97779).
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	—	Specimen Unit Certificate for the Senior Subordinated Series C Units (incorporated by reference to Exhibit 4.8 to our Registration Statement on Form S-3, file No. 333-135951).
4.3	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LBI Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
4.4	—	Registration Rights Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
10.1	—	Fourth Amended and Restated Credit Agreement, dated November 1, 2005, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.2	—	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).

Number		Description
10.3	—	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.4	—	Third Amendment to Fourth Amended and Restated Credit Agreement, effective as of March 28, 2007, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.5	—	Commitment Increase Agreement, dated as of September 19, 2007, among Crosstex Energy, L.P., Bank of America, N.A., and certain lenders party thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K dated September 19, 2007, filed with the Commission on September 24, 2007).
10.6	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
10.7	—	Letter Amendment No. 1 to Amended and Restated Note Purchase Agreement, effective as of March 30, 2007, among Crosstex Energy, L.P., Prudential Investment Management, Inc. and certain other parties (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K dated April 3, 2007, filed with the Commission on April 5, 2007).
10.8	—	Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.9†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan, dated July 12, 2002 (incorporated by reference to Exhibit 10.4 to Annual Report on Form 10-K for the year ended December 31, 2002).
10.10†	—	Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.11	—	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).
10.12†	—	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).
10.13	—	Senior Subordinated Series C Unit Purchase Agreement, dated as of May 16, 2006, by and among Crosstex Energy, L.P. and each of the Purchasers thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated May 16, 2006, filed with the Commission on May 17, 2006).
10.14	—	Seminole Gas Processing Plant Gaines County, Texas Joint Operating Agreement dated January 1, 1993 (incorporated by reference to Exhibit 10.10 to our Registration Statement on Form S-1, file No. 333-106927).
10.15	—	Senior Subordinated Series D Unit Purchase Agreement, dated as of March 23, 2007, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated March 23, 2007, filed with the Commission on March 27, 2007).
10.16†	—	Form of Performance Unit Agreement (incorporated by reference to our current report on Form 8-K dated June 27, 2007, filed with the Commission on July 3, 2007).
21.1*	—	List of Subsidiaries.
23.1*	—	Consent of KPMG LLP.

Number		Description
31.1*	—	Certification of the Principal Executive Officer.
31.2*	—	Certification of the Principal Financial Officer.
32.1*	—	Certification of the Principal Executive Officer and the Principal Financial Officer of the Company pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

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

Exhibit 21.1

LIST OF SUBSIDIARIES

Name of Subsidiary	State of Organization
Crosstex Operating GP, LLC	Delaware
Crosstex Energy Services GP, LLC	Delaware
Crosstex Energy Services, L.P.	Delaware
Crosstex Pipeline, LLC	Texas
Crosstex Pipeline Partners, Ltd.	Texas
Crosstex Gulf Coast Transmission Ltd.	Texas
Crosstex Gulf Coast Marketing Ltd.	Texas
Crosstex CCNG Gathering, Ltd.	Texas
Crosstex CCNG Transmission, Ltd.	Texas
Crosstex CCNG Processing, Ltd.	Texas
Crosstex Treating Services, L.P.	Delaware
Crosstex Alabama Gathering System, L.P.	Delaware
Crosstex Mississippi Industrial Gas Sales, L.P.	Delaware
Crosstex Mississippi Pipeline, L.P.	Delaware
Crosstex Seminole Gas, L.P.	Delaware
Crosstex Acquisition Management, L.P.	Delaware
Crosstex Louisiana Energy, L.P.	Delaware
LIG Chemical GP, LLC	Delaware
LIG Chemical, L.P.	Delaware
LIG Liquids Holdings, L.P.	Delaware
Crosstex LIG, LLC	Louisiana
Crosstex Tuscaloosa, LLC	Louisiana
Crosstex LIG Liquids, LLC	Louisiana
Crosstex DC Gathering Company, J.V.	Texas
Crosstex North Texas Pipeline, L.P.	Texas
Crosstex North Texas Gathering, L.P.	Texas
Crosstex Pelican, LLC	Delaware
Crosstex Processing Services, LLC	Delaware
Crosstex NGL Marketing, L.P.	Texas
Crosstex NGL Pipeline, L.P.	Texas
Sabine Pass Plant Facility, J.V.	Texas

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners
Crosstex Energy, L.P.:

We consent to the incorporation by reference in the registration statements No. 333-116538, 333-128282, 333-134712 and 333-135951 on Forms S-3 and Forms S-8 of Crosstex Energy, L.P. and subsidiaries (No. 333-107025 and 333-127645) of our reports dated February 29, 2008, with respect to the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2007 and 2006, 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, 2007, and all related financial statement schedules, and the effectiveness of internal control over financial reporting as of December 31, 2007, which reports appear in the December 31, 2007 annual report on Form 10-K of Crosstex Energy, L.P. and subsidiaries.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2006, Crosstex Energy, L.P. and subsidiaries adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), Share Based Payment.

KPMG LLP

Dallas, Texas
February 29, 2008

Exhibit 31.1

CERTIFICATIONS

I, Barry E. Davis, President and Chief Executive Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused the disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Barry E. Davis

Barry E. Davis,
President and Chief Executive Officer
(principal executive officer)

Date: February 29, 2008

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, Executive Vice President and Chief Financial Officer of Crosstex Energy GP, LLC, the general partner of Crosstex Energy GP, L.P., the general partner of the registrant, certify that:

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused the disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ William W. Davis

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

Date: February 29, 2008

Exhibit 32.1

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Crosstex Energy, L.P. (the “Registrant”) on Form 10-K for the year ended December 31, 2007 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy GP, LLC, and William W. Davis, Chief Financial Officer of Crosstex Energy GP, LLC, certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Registrant.

/s/ Barry E. Davis

Barry E. Davis
President and Chief Executive Officer

February 29, 2008

/s/ William W. Davis

William W. Davis
Executive Vice President and Chief Financial Officer

February 29, 2008

A signed original of this written statement required by Section 906 has been provided to the Registrant and will be retained by the Registrant and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report.