FORM 10-K

CROSSTEX ENERGY INC - XTXI

Filed: March 01, 2007 (period: December 31, 2006)

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

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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, 2006

OR

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

For the transition period from to

Commission file number: 000-50536

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

Delaware *(State or other jurisdiction of incorporation or organization)*	**52-2235832** *(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 Exchange on which Registered
Common Stock, Par Value $0.01 Per Share	The NASDAQ Global Select Market

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

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was approximately $753,399,000 on June 30, 2006, based on $95.08 per share, the closing price of the Common Stock as reported on the NASDAQ Global Select Market on such date.

At February 16, 2007, there were 45,976,423 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Registrant's Proxy Statement relating to its 2007 Annual Stockholders' Meeting to be filed with the Securities and Exchange Commission are incorporated by reference herein into Part III of this Report.

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DESCRIPTION

CROSSTEX ENERGY, INC.

PART I

Item 1. *Business*

General

Crosstex Energy, Inc. is a Delaware corporation, formed in April 2000. We completed our initial public offering in January 2004. Our shares of common stock are listed on the NASDAQ Global Select Market under the symbol "XTXI". Our executive offices are located at 2501 Cedar Springs, Dallas, Texas 75201, and our telephone number is (214) 953-9500. Our Internet address is www.crosstexenergy.com. In the "Investors" section of our web site, we post the following filings as soon as reasonably practicable after they are electronically filed with or furnished to the Securities and Exchange Commission: our annual report on Form 10-K; our quarterly reports on Form 10-Q; our current reports on Form 8-K; and any amendments to those reports or statements filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. All such filings on our web site are available free of charge. In this report, the terms "Crosstex Energy, Inc." as well as the terms "our," "we," and "us," or like terms, are sometimes used as references to Crosstex Energy, Inc. and its consolidated subsidiaries. References in this report to "Crosstex Energy, L.P.," the "Partnership," "CELP" or like terms refer to Crosstex Energy, L.P. itself or Crosstex Energy, L.P. together with its consolidated subsidiaries.

CROSSTEX ENERGY, INC.

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

- 5,332,000 common units, 4,668,000 subordinated units and 6,414,830 senior subordinated series C units, representing an aggregate 42% limited partner interest in the Partnership; and
- 100% ownership interest in Crosstex Energy GP, L.P., the general partner of the Partnership, which owns a 2.0% general partner interest and all of the incentive distribution rights in the Partnership.

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

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

Distributions by the Partnership have increased from $0.25 per unit for the quarter ended March 31, 2003 (its first full quarter of operations after its initial public offering) to $0.56 per unit for the quarter ended December 31, 2006. As a result, our distributions from the Partnership pursuant to our ownership of an aggregate of 10,000,000 common and subordinated units have increased from $2.5 million for the quarter ended March 31, 2003 to $5.6 million for the quarter ended December 31, 2006; our distributions pursuant to our 2% general partner interest have increased from $74,000 to $0.4 million; and our distributions pursuant to our incentive distribution rights have increased from zero to $5.5 million during this period. The senior subordinated C units do not receive distributions until they convert to common units in February 2008. As a result, we have increased our dividend from $0.10 per share for the quarter ended March 31, 2004 (the first dividend payout after our initial public offering, giving effect to our three-for-one stock split on December 15, 2006) to $0.22 per share for the quarter ended December 31, 2006.

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

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;

- other general and administrative expenses;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities in order to maintain the general partner's 2.0% general partner interest; and
- reserves our board of directors believes prudent to maintain.

If the Partnership is successful in implementing its business strategy and increasing distributions to its partners, we expect to continue to increase dividends to our stockholders, although the timing and amount of any such increased dividends will not necessarily be comparable to the increased Partnership distributions.

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

The Partnership's strategy is to increase distributable cash flow per unit by making accretive acquisitions of assets that are essential to the production, transportation and marketing of natural gas and natural gas liquids, or NGLs, improving the profitability of its assets by increasing their utilization while controlling costs, accomplishing economies of scale through new construction or expansion opportunities in its core operating areas and maintaining financial flexibility to take advantage of opportunities. If the Partnership is successful in implementing this strategy, we believe the total amount of cash distributions it makes will increase and our share of those distributions will also increase. Under its current capital structure, each $0.01 per unit increase in distributions by the Partnership increases its total quarterly distribution by $532,000 and we would receive $366,000 or 69% of that increase.

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

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

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

CROSSTEX ENERGY, L.P.

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

The Partnership has two operating segments, Midstream and Treating. The Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, while the Treating division focuses on the removal of impurities from natural gas to meet pipeline quality specifications. The primary Midstream assets include approximately 5,000 miles of natural gas gathering and transmission pipelines, 12 natural gas processing plants and four fractionators. The gathering systems consist of a network of pipelines that collect natural gas from points near producing wells and transport it to larger pipelines for further transmission. The transmission pipelines primarily receive natural gas from the Partnership's gathering systems and from third party gathering and transmission systems and deliver natural gas to industrial end-users, utilities and other pipelines. The processing plants remove NGLs from a natural gas stream and the Partnership's fractionators separate the NGLs into separate NGL products, including ethane, propane, iso- and normal butanes and natural gasoline. The primary Treating assets include approximately 210 natural gas treating plants and 43 dew point control plants. The Partnership's natural gas treating plants remove carbon dioxide and hydrogen sulfide from natural gas prior to delivering the gas into pipelines to ensure that it meets pipeline quality specifications. See Note 15 to the consolidated financial statements for financial information about these operating segments.

Set forth in the table below is a list of the Partnership's significant acquisitions since January 1, 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

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

Business Strategy

The Partnership's strategy is to increase distributable cash flow per unit by making accretive acquisitions of assets that are essential to the production, transportation and marketing of natural gas and NGLs; accomplishing economies of scale through new construction or expansion in core operating areas; improving the profitability of its assets by increasing their utilization while controlling costs; and maintaining financial flexibility to take advantage of opportunities. It will also build new assets in response to producer and market needs, such as the Partnership's expansion projects located in north Louisiana and north Texas as discussed in "Recent Acquisitions and Expansion" below. We believe the expanded scope of the Partnership's operations, combined with a continued high level of drilling in its principal geographic areas, should present opportunities for continued expansion in its 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 the strategy include the following:

- *Pursuing accretive acquisitions.* The Partnership intends to use its 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. The Partnership pursues acquisitions that it believes will add to existing core areas in order to capitalize on its existing infrastructure, personnel and producer and consumer relationships. The Partnership also examines opportunities to establish new core 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. The Partnership established two new core areas through the acquisition and consolidation of its south Texas assets in 2001 through 2003 and the acquisition of the LIG Pipeline Company and subsidiaries, which we collectively refer to as LIG, in 2004, and the ongoing work to consolidate with the 2005 acquisition of the south Louisiana processing business from El Paso Corporation, or El Paso. With the acquisition of the natural gas gathering pipeline systems and related facilities from Chief Holdings LLC, or Chief, and the completion of construction of the North Texas Pipeline, or NTP, in 2006, the Partnership has established a core area in north Texas.
- *Undertaking construction and expansion opportunities ("organic growth").* The Partnership leverages its existing infrastructure and producer and customer relationships by constructing and expanding systems to meet new or increased demand for gathering, transmission, treating, processing and marketing services. These projects include expansion of existing systems and construction of new facilities, which has driven the growth of the Treating division in recent years. In April 2006, the Partnership completed construction and commenced operations on the new 133-mile NTP to transport gas from the Barnett Shale. The Partnership is in the process of expanding capacity on the NTP, as well as expanding its north Texas processing capacity and completing the buildout of its north Texas gathering system acquired in the Chief acquisition in response to the increased producer activity in this area. The Partnership also has a major expansion of the LIG system underway that is expected to commence operation in 2007, as discussed in detail below. The Partnership continues to pursue organic growth opportunities in Texas, Louisiana and elsewhere.
- *Improving existing system profitability.* After the Partnership acquires or constructs a new system, it begins 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, the Partnership focuses on providing a full range of services to producers and end users, including supply aggregation, transportation and hedging, which the Partnership believes provides a competitive advantage when competing for sources of natural gas supply. Since treating services are not provided by many of the Partnership's competitors, it has an additional advantage in competing for new supply when gas requires treating to meet pipeline specifications. Furthermore, the Partnership emphasizes increasing the percentage of natural gas sales directly to end users, such as industrial and utility consumers, in an effort to increase operating margins.

Recent Acquisitions and Expansion

Chief Midstream Assets. On June 29, 2006, the Partnership acquired 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 as our North Texas Assets, consist of approximately 226 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson Counties, Texas. The acquired assets also include a 125 million cubic feet per day 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 Energy Corporation, or Devon, simultaneously with our acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems.

North Texas Pipeline System. In April 2006, the Partnership completed construction and commenced service on the NTP, a new 133-mile pipeline and associated gathering lines from an area near Fort Worth, Texas to a point near Paris, Texas, with a capacity of approximately 250,000 MMBtu/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 pipeline and other markets. The NTP allows contracted gas to flow to markets that were not previously available to some key Barnett Shale producers. The Partnership plans to expand the NTP in the second quarter of 2007 to a total capacity of approximately 375,000 MMBtu/d. The NTP will interconnect with a new interstate gas pipeline to be constructed by Boardwalk Pipeline Partners, L.P. known as the Gulf Crossing Pipeline. The Gulf Crossing Pipeline will provide the Partnership's customers access to premium midwest and east coast markets. The Partnership has 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 latter part of 2008.

North Louisiana Expansion Project. The Partnership's North Louisiana Expansion project is an extension of its LIG system which is designed to better serve Louisiana intrastate markets and interstate markets, and to provide additional and much needed take-away pipeline capacity to the producers developing natural gas in the fields south of Shreveport, Louisiana. The expansion consists of 63 miles of 24" mainline with 9 miles of 16" gathering lateral pipeline and 10,000 horsepower of compression. Interconnects on the North Louisiana Expansion include connections with the interstate pipelines of ANR Pipeline, Columbia Gulf Transmission, Texas Gas Transmission and Trunkline Gas with additional interconnects under consideration. The capacity of the expansion is approximately 250 MMcf/d. Four of the largest suppliers of natural gas to the new pipeline are El Paso Production, JW Operating, KCS Resources and Winchester Production, which together have committed 185 MMcf/d of capacity. The pipeline is expected to be partially operational in late March 2007 with total completion expected by early May 2007.

Blue Water Processing Plant Acquisition. In May 2006, the Partnership acquired an additional 35.42% interest in the Blue Water gas processing plant for $16.5 million, increasing its total ownership interest to 59.27%. The Partnership also became the operator of the plant in May 2006. The Partnership's initial 23.85% interest in this processing plant was acquired as part of the November 2005 El Paso acquisition.

Cardinal Treating Assets. On October 2, 2006, the Partnership acquired the treating and dew point control business of Cardinal Gas Solutions, L.P. for $6.3 million. The acquired assets include 10 dew point control plants and seven amine treating plants.

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

Other Developments

Three-for-One Stock Split. On December 15, 2006, we completed a three-for-one stock split in the form of a stock dividend. All share amounts in this Annual Report on Form 10-K give effect to such stock split.

Partnership's Issuance of Senior Subordinated Series C Units. On June 29, 2006, the Partnership issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests in a private equity offering for net proceeds of $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represented a discount of 25% to the market value of common units on such date. We purchased 6,414,830 of the senior subordinated series C units. 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 will automatically convert to common units on the first date on or before February 16, 2008 that conversion is permitted by the Partnership's partnership agreement at a ratio of one common unit for each senior subordinated series C unit.

Partnership's Bank Credit Facility. On June 29, 2006, the Partnership amended its bank credit facility to, among other things, provide for revolving credit borrowings up to a maximum principal amount of $1.0 billion. The bank credit agreement includes procedures for additional financial institutions selected by the Partnership to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by the Partnership and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders. The maturity date was also extended to June 2011.

Partnership's Senior Secured Notes. In March and July 2006, the Partnership amended its shelf agreement governing the senior secured notes to increase its availability from $200.0 million to $510.0 million. In March 2006, the Partnership issued $60.0 million aggregate principal amount of senior secured notes with an interest rate of 6.32% and a maturity of ten years. In July 2006, the Partnership issued $245.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years. Proceeds were used to pay indebtedness under its bank credit facility.

June 2006 Issuance of Capital Stock. On June 29, 2006, we issued 7,650,780 shares of common stock in a private placement for total net proceeds of $179.9 million. Lubar Equity Fund, LLC, an affiliate of one of our directors, purchased 468,210 of the shares at a purchase price of $25.633 per share and unrelated third parties purchased 7,182,570 shares at a purchase price of $23.39 per share. We used the proceeds from the stock issuance to purchase $180.0 million of senior subordinated series C units representing limited partner interests of the Partnership described in *"Partnership's Issuance of Senior Subordinated Series C Units"* above.

Midstream Segment

Gathering, Processing and Transmission. The Partnership's primary Midstream assets include systems located primarily along the Texas Gulf Coast and in south-central Mississippi and in Louisiana, which, in the aggregate, consist of approximately 5,000 miles of pipeline, 12 natural gas processing plants and four fractionators and contributed approximately 79% and 76% of its gross margin in 2006 and 2005, respectively.

- *South Louisiana Processing Assets.* The Partnership's Louisiana natural gas processing and liquids business, which was acquired on November 1, 2005 and is referred to as the Partnership's South Louisiana Processing Assets, includes 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.

The South Louisiana Processing Assets primarily consist of:

- *Eunice Processing Plant and Fractionation Facility.* The Eunice facilities are located near Eunice, Louisiana. The Eunice processing plant has a capacity of 1.2 Bcf/d and processed approximately 756 MMcf/d of natural gas for the year ended December 31, 2006. The plant is connected to onshore, continental shelf and deepwater gas production and has downstream connections to the ANR Pipeline, Florida Gas Transmission and Texas Gas Transmission. The Eunice fractionation facility has a capacity of 36,000 barrels per day of liquid products. 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. The Partnership has a five-year storage agreement at the Anse La Butte facility for 100,000 barrels of NGL storage beginning January 1, 2007.
- *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, 2006, the plant processed approximately 370 MMcf/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 15 miles 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 and Transco. For the year ended December 31, 2006, this facility processed approximately 217 MMcf/d.

- *Blue Water Gas Processing Plant.* The Partnership acquired a 23.85% interest in the Blue Water gas processing plant in the November 2005 El Paso acquisition and acquired an additional 35.42% interest in May 2006, at which time it became the operator of the plant. The plant has a net processing capacity to the acquired interest of 186 MMcf/d. For the year ended December 31, 2006, this facility processed approximately 127 MMcf/day 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 Tennessee Gas Pipeline and Columbia Gulf. The facility also performs liquid natural gas (LNG) conditioning services for the Excelerate Energy LNG tanker unloading 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 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 barrels per day. The pipeline transports unfractionated NGLs, referred to as raw make, from the Pelican plant and the Blue Water plant to either the Riverside fractionator or the Napoleonville storage facility. Alternate deliveries can be made to the Eunice plant.

The Partnership contracted to buy the South Louisiana Processing Assets from El Paso two weeks before Hurricane Katrina struck the Gulf Coast, and approximately six weeks before Hurricane Rita struck. While the hurricanes did not do any significant damage to the Partnership's South Louisiana Processing Assets, both hurricanes did extensive damage to Gulf of Mexico drilling, production and transportation facilities. In addition, as a result of the hurricanes, drilling activity in the Gulf of Mexico since that time has been reduced, resulting in an exacerbation of declining trends for production in the area. The Partnership estimates that Gulf of Mexico production is 20-25% below pre-hurricane levels, and as a result, it has lower volumes in the plants than it estimated at the time of the acquisition. This has resulted in 2006 cash flows from the assets at levels significantly below levels the Partnership had anticipated at the time of the acquisition. In addition, a pipeline that supplies natural gas to the Eunice processing plant unilaterally changed the methodology used to allocate fuel and losses. These changes, may result in increased expenses associated with the Eunice Plant operations for the Partnership and its customers. The Partnership is currently in negotiations with the pipeline supplier and evaluating its remedies. The Partnership is evaluating alternative strategies for the operation of the assets that it believes will significantly improve cash flows.

- *North Texas Assets.* On June 29, 2006, the Partnership acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale. The acquired systems consist of approximately 226 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties, Texas. The acquired assets also include a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. At the closing of that transaction, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with the Partnership's acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. Immediately following the closing of the Chief acquisition, we began expanding our North Texas pipeline gathering system. As of December 31, 2006, the Partnership had installed approximately 49 miles of gathering pipeline and connected 85 new wells to its gathering systems, 46 of which are owned or controlled by Devon and 39 of which are owned or controlled by other producers. In addition to expanding its gathering system, the Partnership had installed 4,400 horsepower of additional compression to handle the increased volumes. The Partnership also installed the new Azle Plant, a 55,000 Mcf/d cryogenic processing plant and added inlet refrigeration to an existing

30,000 Mcf/d plant in order to remove hydrocarbon liquids from growing gas streams. The Partnership has increased total throughput on this gathering system from approximately 115 MMcf/d at the time of the acquisition to 230 MMcf/d for the month of December 2006.

- The Partnership plans to expand its NTP system in the second quarter of 2007 to a total capacity of approximately 375,000 MMBtu/day.
- The Partnership has committed to contract for 150,000 MMBtu/day 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 the Partnership's NTP system in Lamar County, Texas. The Gulf Crossing Pipeline will provide the Partnership's customers access to premium midwest and east coast markets.

- *LIG System.* The Partnership acquired the LIG system on April 1, 2004. The LIG system is the largest intrastate pipeline system in Louisiana, consisting of approximately 2,000 miles of gathering and transmission pipeline, and had an average throughput of approximately 692,000 MMBtu/d for the year ended December 31, 2006. The system also includes two operating processing plants with an average throughput of 328,000 MMBtu/d for the year ended December 31, 2006. 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. The Partnership is extending its LIG system to better serve its customers. The North Louisiana 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 250 MMcf/d. The pipeline is expected to be partially operational in late March 2007 with total completion expected by early May 2007.
- *South Texas System.* The Partnership has 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/d. 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, 2006 was approximately 457,000 MMBtu/d. Average throughput in the processing plant was approximately 99,000 MMBtu/d for that period. 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.

Other Midstream assets and activities include:

- *Mississippi Pipeline System.* This approximately 603-mile system in south Mississippi gathers wellhead supply in the region and sells it through direct market connections to utilities and industrial end-users. Average throughput on the system was approximately 107,000 MMBtu/d for the year ended December 31, 2006.
- *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, 2006, throughput on the system averaged approximately 22,000 MMBtu/d.
- *Other.* Other midstream assets consist of a variety of gathering lines and a processing plant with a processing capacity of approximately 66,000 Bcf/d. Total volumes gathered and resold were approximately 65,000 MMBtu/d for the year ended December 31, 2006. Total volumes processed were approximately 22,000 MMBtu/d in the period.
- *Off-System Services.* The Partnership offers natural gas marketing services on behalf of producers for natural gas that does not move on its assets. It markets this gas on a number of interstate and intrastate pipelines. These volumes averaged approximately 139,000 MMBtu/d in 2006.

Treating Segment

The Partnership operates (or leases to producers for operation) treating plants that remove carbon dioxide and hydrogen sulfide from natural gas before it is delivered into transportation systems to ensure that it meets pipeline quality specifications. The treating division contributed approximately 21% and 24% of the Partnership's gross margin in 2006 and 2005, respectively. The Partnership's treating business has grown from 112 plants in operation at December 31, 2005 to 160 plants in operation at December 31, 2006. During 2006, the Partnership 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. Pipeline companies have begun enforcing gas quality specifications to lower the dew point of the gas they receive and transport. A higher relative dew point can sometimes cause liquid hydrocarbons to condense in the pipeline and cause operating problems and gas quality issues to the downstream markets. Hydrocarbon dew point plants are skid mounted process equipment that remove these hydrocarbons. Typically these plants use a Joules-Thompson expansion process to lower the temperature of the gas stream and collect the liquids before they enter the downstream pipeline. The Partnership's Treating division views dew point control as complementary to its treating business.

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

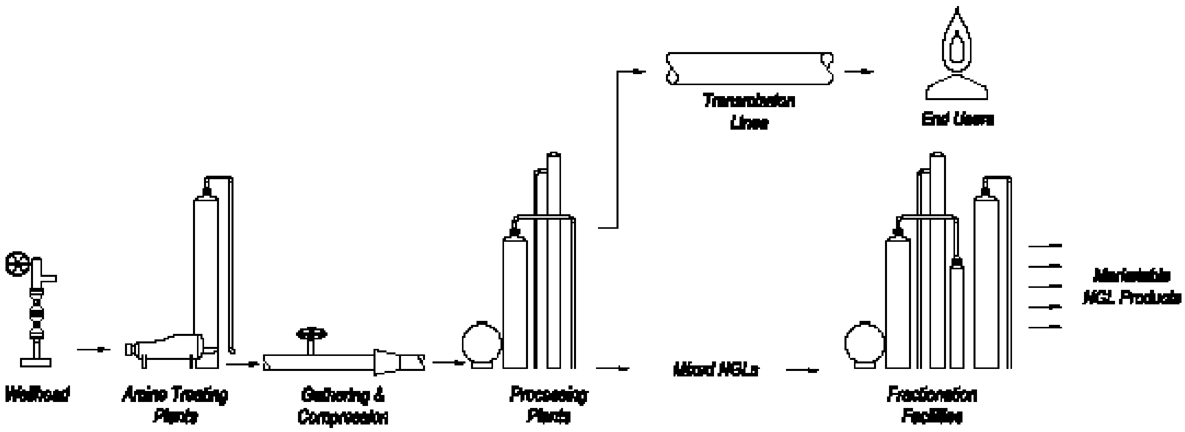
The Partnership also owns an undivided 12.4% interest in the Seminole gas processing plant, which is located in Gaines County, Texas, and which is accounted for as part of the Treating division. The Seminole plant has dedicated long-term reserves from the Seminole San Andres unit, to which it also supplies 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 50% of the NGLs produced by the plant.

The Partnership's treating growth strategy is based on the belief that if gas prices remain at recent levels, producers will be encouraged to drill deeper gas formations. It believes the gas recovered from these 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. The Partnership believes its track record of reliability, current availability of equipment and its strategy of sourcing new equipment gives it 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 begins with 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. Natural gas has a varied composition depending on the field, the formation and the reservoir from which it is produced. Natural gas from certain formations is high in carbon dioxide. Most treating plants and transmission pipelines are placed at or near a well and remove carbon dioxide and hydrogen sulfide from natural gas before it is introduced into gathering systems 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. The Partnership's Treating division views dew point control as complementary to its 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. Most natural gas produced by a well is not 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 the Partnership purchases natural gas, it normally establishes a margin by selling natural gas for physical delivery to third-party users. It 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, it seeks to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Its 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 natural gas gathering, transmission, treating, processing and marketing services for natural gas and NGLs is highly competitive. The Partnership faces strong competition in acquiring new natural gas supplies and in the marketing and transportation of natural gas and NGLs. Its competitors include major integrated oil companies, 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 its competitors offer more services or have greater financial resources and access to larger natural gas supplies than we do. The Partnership's competition will likely differ in different geographic areas.

The Partnership's gas treating operations face competition from manufacturers of new treating and dew point control plants and from a small number of regional operators that provide plants and operations similar to the Partnership. It also faces competition from vendors of used equipment that occasionally operate plants for producers. In addition, the Partnership routinely loses business to gas gatherers who have underutilized treating or processing capacity and can take the producers' gas without requiring wellhead treating. The Partnership may also lose wellhead treating opportunities to blending. 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, the Partnership has numerous competitors, including marketing affiliates of interstate pipelines, major integrated oil companies, and local and national natural gas gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Local utilities and distributors of natural gas are, in some cases engaged directly, and through affiliates, in marketing activities that compete with the Partnership.

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

Natural Gas Supply

The Partnership's transmission pipelines have connections with major interstate and intrastate pipelines, which it believes have ample supplies of natural gas in excess of the volumes required for these systems. In connection with the construction and acquisition of gathering systems, the Partnership evaluates well and reservoir data furnished by producers to determine the availability of natural gas supply for the systems and/or obtain a minimum volume commitment from the producer that results in a rate of return on the investment. Based on these facts, the Partnership believes that there should be adequate natural gas supply to recoup the investment with an adequate rate of return. It does not routinely obtain independent evaluations of reserves dedicated to its systems due to the cost and relatively limited benefit of such evaluations. Accordingly, it does not have estimates of total reserves dedicated to its systems or the anticipated life of such producing reserves.

Credit Risk and Significant Customers

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

During the year ended December 31, 2006, the Partnership had one customer that individually accounted for approximately 13.4% of consolidated revenues. While this customer represents a significant percentage of consolidated revenues, the loss of this customer would not have a material impact on its results of operations.

Regulation

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

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

The rates, terms and conditions of service under which the Partnership transports natural gas in its pipeline systems in interstate commerce are subject to FERC 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 the 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 each subject to review in 2006 and no substantial changes were made to their rates.

Intrastate Pipeline Regulation. The Partnership's 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. The Partnership owns 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.

The Partnership is 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 the Partnership sells natural gas currently is not subject to federal regulation and, for the most part, is not subject to state regulation. The Partnership's 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 the Partnership's 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 the Partnership will be affected by any such FERC action materially differently than other natural gas marketers with whom they compete.

Environmental Matters

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

Any failure to comply with applicable environmental laws and regulations, including those relating to obtaining required governmental approvals, may result in the assessment of administrative, civil or criminal penalties, imposition of investigatory or remedial activities and, in less common circumstances, issuance of injunctions or construction bans or delays. While we believe that the Partnership currently holds all material governmental approvals required to operate its major facilities, the Partnership is currently evaluating and updating permits for certain of its facilities specifically including those obtained in recent acquisitions. As part of the regular overall evaluation of its operations, the Partnership has implemented procedures and is presently working to ensure that all governmental approvals, for both recently acquired facilities and existing operations, are updated as may be necessary. We believe that the Partnership's operations and facilities are in substantial compliance with applicable environmental laws and regulations and that the cost of compliance with such laws and regulations will not have a material adverse effect on its operating results or financial condition.

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

Hazardous Substance and Waste. To a large extent, the environmental laws and regulations affecting the Partnership's possible future operations relate to the release of hazardous substances or solid wastes into soils, groundwater, and surface water, and include measures to control environmental 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, the Partnership may generate wastes that may fall within the definition of a "hazardous substance." The Partnership may be responsible under CERCLA for all or part of the costs required to clean up sites at which such wastes have been disposed. The Partnership has not received any notification that it may be potentially responsible for cleanup costs under CERCLA or any analogous state laws.

The Partnership also generates, and may in the future generate, both hazardous and nonhazardous solid wastes that are subject to requirements of the federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. 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. The Partnership is not currently required to comply with a substantial portion of the RCRA requirements because its operations generate minimal quantities of hazardous wastes. However, it is possible that some wastes generated by it that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements. Changes in applicable regulations may result in an increase in the Partnership's capital expenditures or plant operating expenses.

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

The Partnership acquired the South Louisiana Processing Assets from El Paso in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has a known active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the guidance of the Louisiana Department of Environmental Quality (LDEQ) based on the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. 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. The estimated remediation costs are expected to be approximately $0.5 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to the Partnership's ownership, these costs were accrued as part of the purchase price.

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

The Partnership acquired assets from Duke Energy Field Services, L.P. (DEFS) in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations had been identified at levels that exceeded the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The 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. The Partnership does not expect to incur any material liability in connection with the remediation associated with this site.

Air Emissions. The Partnership's current and 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, the Partnership's gathering, treating and processing of natural gas, fractionation and storage of NGLs, or facilities therefor or any of its 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 the Partnership's operations, could cause capital expenditures to be incurred 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 the Partnership's 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 the Partnership's 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. The Partnership believes that it is in substantial compliance with Clean Water Act permitting requirements as well as the conditions imposed thereunder, and that continued compliance with such existing permit conditions will not have a material effect on its results of operations.

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

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

Office Facilities

In addition to the Partnership's gathering and treating facilities discussed above, the Partnership occupies approximately 95,400 square feet of space at its executive offices in Dallas, Texas under a lease expiring in June 2014 and approximately 16,000 square feet of office space for the Partnership's south Louisiana operations in Houston, Texas with lease terms expiring in January 2013.

Employees

As of December 31, 2006, the Partnership (through its subsidiaries) employed approximately 610 full-time employees. Approximately 287 of the employees were general and administrative, engineering, accounting and commercial personnel and the remainder were operational employees. The Partnership is not party to any collective bargaining agreements, and has not had any significant labor disputes in the past. We believe that the Partnership has good relations with its employees.

Item 1A. *Risk Factors*

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

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

Our only cash-generating assets are our partnership interests in Crosstex Energy, L.P. Our cash flow is therefore completely dependent upon the ability of the Partnership to make distributions to its partners. The amount of cash that the Partnership can distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the amount of natural gas transported in its gathering and transmission pipelines;
- the level of the Partnership's processing and treating operations;

- the fees the Partnership charges and the margins it realizes for its services;
- the price of natural gas;
- the relationship between natural gas and NGL prices; and
- its level of operating costs.

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

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

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

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

In our corporate charter, we have renounced business opportunities that may be pursued by the Partnership or by affiliated stockholders that hold a majority of our common stock.

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

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

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

A significant portion of our partnership interests in the Partnership are subordinated to the common units.

We own 16,414,830 units representing limited partner interests in the Partnership, of which 4,668,000 are subordinated units, 6,414,830 are senior subordinated series C units and 5,332,000 are common units. The senior subordinated series C units will automatically convert into common units on the first date on or after February 16, 2008 that conversion is permitted by the Partnership's partnership agreement. Generally, the senior subordinated series C units will not be entitled to participate in the Partnership's distributions of available cash until February 16, 2008. During the subordination period, the subordinated units will not receive any distributions in a quarter until the Partnership has paid the minimum quarterly distribution of $0.25 per unit, plus any arrearages in the payment of the minimum quarterly distribution from prior quarters, on all of the outstanding common units. Distributions on the subordinated units are therefore more uncertain than distribution on the common units. Furthermore, no distributions may be made on the incentive distribution rights until the minimum quarterly distribution has been paid on all outstanding units. Therefore, distributions with respect to the incentive distribution rights are even more uncertain than distributions on the subordinated units. Neither the subordinated units nor the incentive distribution rights are entitled to any arrearages from prior quarters.

Generally, the subordination period ends, and the subordinated units convert to common units, only after December 31, 2007 and only upon the satisfaction of certain financial tests.

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

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

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

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

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

The general partner may make expenditures on behalf of the Partnership for which it will seek reimbursement from the Partnership. In addition, under Delaware partnership law, the general partner, in its capacity as the general partner of the Partnership, has unlimited liability for the obligations of the Partnership, such as its debts and environmental liabilities, except for those contractual obligations of the Partnership that are expressly made without recourse to the general partner. To the extent the general partner incurs obligations on behalf of the Partnership, it is entitled to be reimbursed or indemnified by the general partner. In the event that the Partnership is unable or unwilling to reimburse or indemnify the general partner, the general partner may be unable to satisfy these liabilities or obligations, which would reduce its value and therefore the value of our common stock.

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

The Partnership's future financial performance will depend, in part, on its ability to make acquisitions of assets and businesses at attractive prices. From time to time, the Partnership will evaluate and seek to acquire assets or businesses that it believes complements existing business and related assets. The Partnership may acquire assets or businesses that it plans to use in a manner materially different from their prior owner's use. Any acquisition involves potential risks, including:

- the inability to integrate the operations of 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 the Partnership's 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 the Partnership's operations and cash flows. If the Partnership consummates any future acquisition, its capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that the Partnership will consider in determining the application of these funds and other resources.

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

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

If the Partnership's assumptions used in making the acquisition of the Barnett Shale systems and facilities from Chief Holdings LLC are inaccurate, its future financial performance may be limited.

The Partnership acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale from Chief Holdings LLC in June 2006. This acquisition was made based on the Partnership's understanding of future drilling plans by Devon Energy Corporation, which acquired Chief's producing assets and acreage previously owned by Chief that is dedicated to the acquired systems. In addition, the Partnership assumed in its analysis the continued drilling success by other producers that own acreage dedicated to those systems, production success on acreage not dedicated to the system and that it will be able to tie a certain portion of that new production into the systems. Production currently flowing through the systems is very small relative to the quantities the Partnership has assumed will be developed in the next few years. If its assumptions are inaccurate, the drilling plans of the producers are delayed, the producers are not successful in completing their wells or the Partnership is not successful in its commercial efforts to tie in gas from undedicated acreage, then its anticipated results from the acquisition from Chief of these assets could be significantly negatively impacted. In addition, the failure to successfully integrate these assets with the Partnership's existing business and operations in a timely manner may have a material adverse effect on its business, financial condition, results of operations and cash flows.

The Partnership is vulnerable to operational, regulatory and other risks associated with south Louisiana and the Gulf of Mexico, including the effects of adverse weather conditions such as hurricanes, because a significant portion of its assets are located in south Louisiana.

Operations and revenues will be significantly impacted by conditions in south Louisiana because the Partnership has a significant portion of its assets located in south Louisiana. This concentration of activity makes the Partnership more vulnerable than many of its 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 the Partnership's operations could experience the same condition at the same time, these conditions could have a relatively greater impact on results of operations than they might have on other midstream companies who have operations in a more diversified geographic area.

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

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

The Partnership is subject to significant risks due to fluctuations in commodity prices. These risks are based upon three components of business: (1) it purchases certain volumes of natural gas at a price that is a percentage of a relevant index; (2) certain processing contracts for its Gregory system and its Plaquemine and Gibson processing plants expose the Partnership to natural gas and NGL commodity price risks; and (3) part of its fees from the 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 the Partnership realizes from purchasing and selling a portion of the natural gas that it transports through its pipeline systems decrease in periods of low natural gas prices because gross margins related to such purchases are based on a percentage of the index price. For the years ended December 31, 2005 and 2006, the Partnership purchased approximately 7.5% and 5.9%, respectively, of its gas at a percentage of relevant index. Accordingly, a decline in the price of natural gas could have an adverse impact on its results of operations.

A portion of the Partnership's profitability is affected by the relationship between natural gas and NGL prices. For a component of the Gregory system and the Plaquemine plant and Gibson plant volumes, natural gas is purchased, processed and NGLs are extracted, and then the processed natural gas and NGLs are sold. A portion of profits from the plants acquired in the El Paso acquisition is dependent on NGL prices and elections by the Partnership and the producers. In cases where the Partnership processes gas for producers when they have the ability to decide whether to process their gas, it may elect to receive a processing fee or it may retain and sell the NGLs and keep the producer whole on its sale of natural gas. Since the Partnership extracts energy content, which is measured in Btu's, from the gas stream in the form of the liquids or consume it as fuel during processing, the Partnership reduces the Btu content of the natural gas. Accordingly, 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 this volatility is expected to continue. For example, in 2005, the NYMEX settlement price for natural gas for the prompt month contract ranged from a high of $13.91 per MMBtu to a low of $6.12 per MMBtu. In 2006, the same index ranged from $11.43 per MMBtu to $4.20 per MMBtu. A composite of the OPIS Mt. Belvieu monthly average liquids price based upon our average liquids composition in 2005 ranged from a high of approximately $1.16 per gallon to a low of approximately $0.80 per gallon. In 2006, the same composite ranged from approximately $1.20 per gallon to approximately $0.90 per gallon.

The Partnership may not be successful in balancing 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 less than contracted volumes. Any of these actions could cause purchases and sales not to be balanced. If purchases and sales are not balanced, the Partnership will face increased exposure to commodity price risks and could have increased volatility in operating income.

The markets and prices for residue gas and NGLs depend upon factors beyond the Partnership's control. These factors include demand for oil, natural gas and NGLs, which 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.

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

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

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

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

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

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

One of the ways the Partnership intends to grow business is through the construction of or additions to existing gathering systems and construction of new pipelines and gathering, processing and treating facilities. The construction of pipelines and gathering, processing and treating facilities requires the expenditure of significant amounts of capital, which may exceed the Partnership's expectations. Generally, the Partnership may have only limited natural gas supplies committed to these facilities prior to their construction. Moreover, the Partnership may construct facilities to capture anticipated future growth in production in a region in which anticipated production growth does not materialize. The Partnership may also rely on estimates of proved reserves in the decision to construct new pipelines and facilities, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved reserves. As a result, new facilities may not be able to attract enough natural gas to achieve the expected investment return, which could adversely affect its results of operations and financial condition. In addition, the Partnership faces the risks of construction delay and additional costs due to obtaining rights-of-way.

The Partnership has limited control over the development of certain assets because it is not the operator.

As the owner of non-operating interests in the Seminole gas processing plant, the Partnership does not have the right to direct or control the operation of the plants. 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 the Partnership's 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 these plants, including environmental laws and regulations, in a proper manner could result in material adverse consequences to the Partnership's interest and adversely affect the Partnership's results of operations.

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

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

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

Risks of nonpayment and nonperformance by the Partnership's customers is a major concern in its business. The Partnership is subject to risks of loss resulting from nonpayment or nonperformance by its customers. Any increase in the nonpayment and nonperformance by its customers could adversely affect results of the Partnership's operations.

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

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

For the year ended December 31, 2006, approximately 71% of the Partnership's sales of gas which were transported using its physical facilities were to industrial end-users and utilities. As a consequence of the increase in competition in the industry and volatility of natural gas prices, end-users and utilities are reluctant to enter into long-term purchase contracts. Many end-users purchase natural gas from more than one natural gas company and have the ability to change providers at any time. Some of these end-users also have the ability to switch between gas and alternate fuels in response to relative price fluctuations in the market. Because there are numerous companies of greatly varying size and financial capacity that compete with the Partnership in the marketing of natural gas, the Partnership often competes in the end-user and utilities markets primarily on the basis of price. The inability of the Partnership's management to renew or replace current contracts as they expire and to respond appropriately to changing market conditions could have a negative effect on its profitability.

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

The Partnership derives a significant portion of its revenues from contracts with key customers. To the extent that these and other customers may reduce volumes of natural gas purchased under existing contracts, the Partnership would be adversely affected unless it was 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.

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

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

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

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

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

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

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

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

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

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

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

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

Compliance with pipeline integrity regulations issued by the TRRC, or those issued by the United States Department of Transportation in December of 2003 could result in substantial expenditures for testing, repairs and replacement. TRRC regulations require periodic testing of all intrastate pipelines meeting certain size and location requirements. the Partnership's costs relating to compliance with the required testing under the TRRC regulations were approximately $1.1 million, $0.3 million and $1.9 million for the years ended December 31, 2006, 2005 and

2004, respectively, and it expects the costs for compliance with TRRC and DOT regulations to be $5.6 million during 2007. If the Partnership's pipelines fail to meet the safety standards mandated by the TRRC or the DOT regulations, then the Partnership may be required to repair or replace sections of such pipelines, the cost of which cannot be estimated at this time.

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

Many of the operations and activities of the Partnership's gathering systems, plants and other facilities, including the natural gas and processing liquids business in South Louisiana recently acquired from El Paso, 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 the Partnership's facilities and the cleanup of hazardous substances and other wastes that may have been released at properties currently or previously owned or operated by the Partnership or locations to which it has sent wastes for treatment or disposal. Various governmental authorities have the power to enforce compliance with these regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Strict, joint and several liability may be incurred under these laws and regulations for the remediation of contaminated areas. Private parties, including the owners of properties through which the Partnership's gathering systems pass, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage.

There is inherent risk of the incurrence of significant environmental costs and liabilities in the Partnership's business due to its handling of natural gas and other petroleum products, air emissions related to the Partnership's 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 the Partnership's compliance costs and the cost of any remediation that may become necessary. The Partnership may incur material environmental costs and liabilities. Furthermore, insurance may not provide sufficient coverage in the event an environmental claim is made against the Partnership.

The Partnership's business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. New environmental regulations might adversely affect the Partnership's 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 the Partnership's profitability.

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

The Partnership uses over-the-counter price and basis swaps with other natural gas merchants and financial institutions, and it uses futures and option contracts traded on the New York Mercantile Exchange. Use of these instruments is intended to reduce exposure to short-term volatility in commodity prices. The Partnership 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 its counterparties fails to perform under a contract.

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

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

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

The Partnership depends on the continued employment and performance of the officers of Crosstex Energy GP, LLC and key operational personnel. Crosstex Energy GP, LLC enters into employment agreements with each of its executive officers. If any of these officers or other key personnel resign or become unable to continue in their present roles and are not adequately replaced, the Partnership's business operations could be materially adversely affected. The Partnership does not maintain any "key man" life insurance for any officers.

Item 1B. *Unresolved Staff Comments*

We do not have any unresolved staff comments.

Item 2. *Properties*

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

Title to Properties

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

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

Item 3. *Legal Proceedings*

Our operations and those of the Partnership are subject to a variety of risks and disputes normally incident to our business. As a result, at any given time we or the Partnership may be a defendant in various legal proceedings and litigation arising in the ordinary course of business. These include litigation on disputes related to contracts, property rights, use or damage and personal injury. We do not believe that any pending or threatened claim or dispute is material to our financial results or our operations. We maintain insurance policies with insurers in amounts and with coverage and deductibles as we believe are reasonable and prudent. However, this insurance may not be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

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

We held a special meeting of stockholders on October 26, 2006. At the meeting, the following proposals were approved by the margins indicated below:

1. To amend the Company's Restated Certificate of Incorporation (a) to increase our authorized capital stock from 20,000,000 shares, consisting of 19,000,000 shares of common stock and 1,000,000 shares of preferred stock, to 150,000,000 shares, consisting of 140,000,000 shares of common stock and 10,000,000 shares of preferred stock, and (b) to clarify the liquidation provision applicable to our common stock.

For	9,221,442
Against	2,287,524
Abstain	15,564
Broker Non-Votes	0

2. To approve the Crosstex Energy, Inc. Long-Term Incentive Plan (including the increase in the number of shares available for issuance thereunder).

For	9,284,243
Against	2,156,983
Abstain	83,302
Broker Non-Votes	0

PART II

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

Our common stock is listed on the NASDAQ Global Select Market under the symbol "XTXI". Our common stock began trading on January 12, 2004. On February 16, 2007, the market price for our common stock was $31.33 per share and there were approximately 12,200 record holders and beneficial owners (held in street name) of the shares of our common stock.

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

	Common Stock Price Range(a)		
	High	Low	Cash Dividends Paid per Share
2006:			
Quarter Ended December 31	$ 33.00	$ 28.28	$ 0.220
Quarter Ended September 30	33.44	27.33	0.213
Quarter Ended June 30	32.00	23.83	0.207
Quarter Ended March 31	27.87	21.07	0.200
2005:			
Quarter Ended December 31	$ 23.14	$ 18.86	$ 0.187
Quarter Ended September 30	22.35	16.02	0.153
Quarter Ended June 30	16.20	14.28	0.143
Quarter Ended March 31	14.72	13.22	0.137

(a) Share prices and cash dividends per share have been adjusted for the three-for-one stock split on December 15, 2006.

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

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

• reserves our board of directors believes prudent to maintain.

If the Partnership continues to be successful in implementing its business strategy and increasing distributions to its partners, we would expect to continue to increase dividends to our stockholders, although the timing and amount of any such increased dividends will not necessarily be comparable to the increased Partnership distributions.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors deems relevant. The Partnership's debt agreements contain restrictions on the payment of distributions and prohibit the payment of distributions if the Partnership is in default. If the Partnership cannot make incentive distributions to the general partner or limited partner distributions to us, we will be unable to pay dividends on our common stock.

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected In Column(a)) (c)
Equity Compensation Plans Approved By Security Holders(1)	871,749(2)	$ 8.21(3)	1,123,215
Equity Compensation Plans Not Approved By Security Holders	N/A	N/A	N/A

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

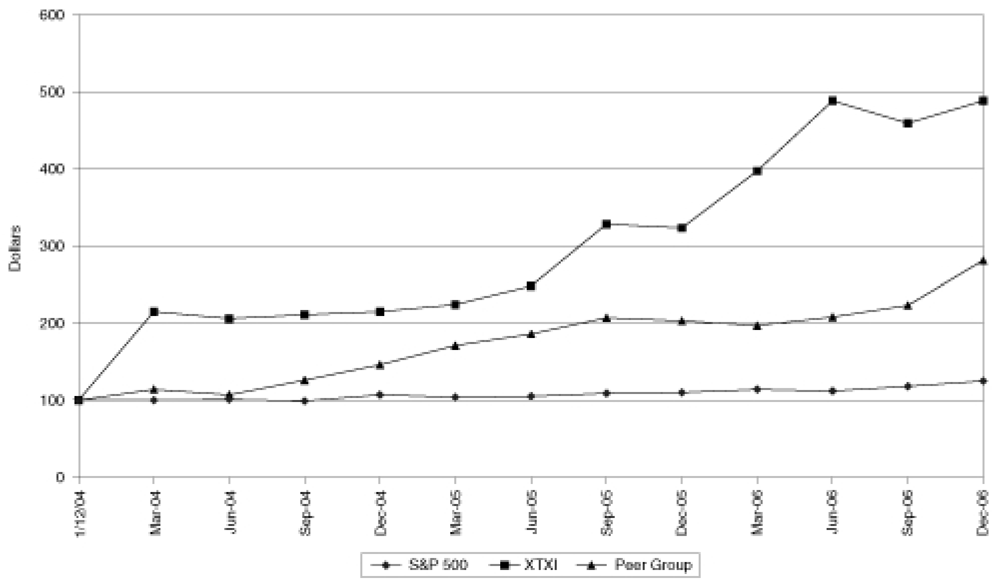
(2) The number of securities includes 751,749 restricted shares that have been granted under our long-term incentive plan that have not vested.

(3) The exercise prices for outstanding options under the plan as of December 31, 2006 range from $6.50 to $13.33 per share.

Performance Graph

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

COMPARISON OF CUMULATIVE RETURNS SINCE JANUARY 12, 2004
AMONG CROSSTEX ENERGY, INC., S&P 500 AND PEER GROUP



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

The following table sets forth selected historical financial and operating data of Crosstex Energy, Inc. as of and for the dates and periods indicated. The selected historical financial data are derived from the audited financial statements of Crosstex Energy, Inc. The summary historical financial and operating include the results of operations of the Vanderbilt system beginning in December 2002, the Mississippi pipeline system and the Seminole processing plant beginning in June 2003, the LIG assets beginning in April 2004, the South Louisiana Processing Assets beginning November 2005, the Hanover assets beginning January 2006, the NTP beginning April 2006, the Midstream assets acquired from Chief beginning June 29, 2006 and other smaller acquisitions completed during 2006.

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

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	Year Ended December 31,				
	2006	2005	2004	2003	2002
	(Dollars in thousands, except per share amounts)				
Statement of Operations Data:					
Revenues:					
Midstream	$ 3,073,069	$ 2,982,874	$ 1,948,021	$ 989,697	$ 437,432
Treating	66,225	48,606	30,755	23,966	14,817
Profit on energy trading activities	2,510	1,568	2,228	2,266	1,791
Total revenues	3,141,804	3,033,048	1,981,004	1,015,929	454,040
Operating costs and expenses:					
Midstream purchased gas	2,859,815	2,860,823	1,861,204	946,412	414,244
Treating purchased gas	9,463	9,706	5,274	7,568	5,767
Operating expenses	101,036	56,768	38,396	19,880	11,420
General and administrative	47,707	34,145	22,005	14,816	7,704
Impairments	—	—	981	—	4,175
(Gain) loss on energy trading contracts	(1,599)	9,968	(279)	361	134
Gain on sale of property	(2,108)	(8,138)	(12)	—	—
Depreciation and amortization	82,792	36,070	23,034	13,542	7,745
Total operating costs and expenses	3,097,106	2,999,342	1,950,603	1,002,579	451,189
Operating income	44,698	33,706	30,401	13,350	2,851
Other income (expense):					
Interest expense, net	(51,051)	(15,332)	(9,115)	(3,103)	(2,381)
Other income (expense)	1,774	391	802	179	(52)
Total other income (expense)	(49,277)	(14,941)	(8,313)	(2,924)	(2,433)
Income (loss) before gain on issuance of units by the partnership, income taxes and interest of non-controlling partners in the partnership’s net income	(4,579)	18,765	22,088	10,426	418
Gain on issuance of partnership units(1)	18,955	65,070	—	18,360	11,781
Income tax provision benefit	(11,118)	(30,047)	(5,149)	(10,157)	(6,871)
Interest of non-controlling partners in the partnership’s net income	(13,027)	(4,652)	(8,239)	(5,181)	(99)
Net income before cumulative effect of change in accounting principle	16,285	49,136	8,700	13,448	5,229
Cumulative effect of change in accounting principle	170	—	—	—	—
Net income	$ 16,455	$ 49,136	$ 8,700	$ 13,448	$ 5,229

Net income per common share-basic(2)	$	0.39	$	1.29	$	0.24	$	0.94	$	0.20
Net income per common share-diluted(2)	$	0.39	$	1.26	$	0.22	$	0.37	$	0.15

	Year Ended December 31, 2006	2005	2004	2003	2002
	(Dollars in thousands, except per share amounts)				
Balance Sheet Data (end of period):					
Working capital surplus (deficit)	$ (70,091)	$ 4,872	$ (18,265)	$ (7,705)	$ (11,141)
Property and equipment, net	1,107,242	668,632	325,653	104,890	111,203
Total assets	2,206,698	1,445,325	606,768	370,485	241,424
Long-term debt	987,130	522,650	148,700	60,750	22,550
Interest of non-controlling partners in the partnership	391,103	264,726	65,399	67,157	26,815
Stockholders' equity	279,413	111,247	76,933	69,266	57,397
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 113,840	$ 12,842	$ 46,339	$ 42,103	$ (5,050)
Investing activities	(885,825)	(614,822)	(124,371)	(110,288)	(33,240)
Financing activities	769,717	592,365	99,072	65,856	41,746
Other Financial Data:					
Midstream gross margin	$ 215,764	$ 123,619	$ 89,045	$ 45,551	$ 24,979
Treating gross margin	56,762	38,900	25,481	16,398	9,050
Total gross margin(3)	$ 272,526	$ 162,519	$ 114,526	$ 61,949	$ 34,029
Operating Data:					
Pipeline throughput (MMBtu/d)	1,450,000	1,222,000	1,289,000	626,000	392,000
Natural gas processed (MMBtu/d)(4)	1,938,000	1,825,000	425,000	132,000	86,000
Producer services (MMBtu/d)	138,000	175,000	210,000	259,000	230,000

(1) We recognized gains of $19.0 million in 2006, $65.1 million in 2005, $18.4 million in 2003 and $11.8 million in 2002 as a result of the Partnership issuing additional units to the public in public offerings at prices per unit greater than our equivalent carrying value.

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

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

(4) Processed volumes during 2005 include a daily average for the south Louisiana processing plants for November 2005 and December 2005, the two-month period these assets were operated by the Partnership.

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

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

Overview

Crosstex Energy, Inc. is a Delaware corporation formed on April 28, 2000 to engage in the gathering, transmission, treating, processing and marketing of natural gas and NGLs through its subsidiaries. On July 12, 2002, we formed Crosstex Energy, L.P., a Delaware limited partnership, to acquire indirectly substantially all of the assets, liabilities and operations of its predecessor, Crosstex Energy Services, Ltd. Our assets consist almost exclusively of partnership interests in Crosstex Energy, L.P., a publicly traded limited partnership engaged in the gathering, transmission, treating, processing and marketing of natural gas and NGLs. These partnership interests consist of (i) 5,332,000 common units, 4,668,000 subordinated units and 6,414,830 senior subordinated series C units, representing approximately 42% of the limited partner interests in Crosstex Energy, L.P., and (ii) 100% ownership interest in Crosstex Energy GP, L.P., the general partner of Crosstex Energy, L.P., which owns a 2.0% general partner interest and all of the incentive distribution rights in

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

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

Distributions by the Partnership have increased from $0.25 per unit for the quarter ended March 31, 2003 (its first full quarter of operation after its initial public offering) to $0.56 per unit for the quarter ended December 31, 2006. As a result, our distributions from the Partnership pursuant to our ownership of our 10,000,000 common and subordinated units have increased from $2.5 million for the quarter ended March 31, 2003 to $5.6 million for the quarter ended December 31, 2006; our distributions pursuant to our 2% general partner interest have increased from $74,000 to $0.4 million; and our distributions pursuant to our incentive distribution rights have increased from zero to $5.5 million. As a result, we have increased our dividend from $0.10 per share (giving effect to the three-for-one stock split on December 15, 2006) for the quarter ended March 31, 2004 (the first dividend payout after our initial public offering) to $0.22 per share for the quarter ended December 31, 2006.

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

The Partnership has two industry segments, Midstream and Treating, with a geographic focus along the Texas gulf coast, in the north Texas Barnett Shale area and in Mississippi and Louisiana. The Partnership's Midstream division focuses on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services, while the Treating division focuses on the removal of contaminants from natural gas and NGLs to meet pipeline quality specifications. For the year ended December 31, 2006, 79% of the Partnership's gross margin was generated in the Midstream division, with the balance in the Treating division. The Partnership focuses on gross margin to manage its business because its business is generally to purchase and resell natural gas for a margin, or to gather, process, transport, market or treat natural gas or NGLs for a fee. The Partnership buys and sells most of its natural gas at a fixed relationship to the relevant index price so margins are not significantly affected by changes in natural gas prices. As explained under "Commodity Price Risk" below, it enters into financial instruments to reduce volatility in gross margin due to price fluctuations.

During the past five years, the Partnership has grown significantly as a result of construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2002 through December 31, 2006, it has invested over $1.7 billion to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition. As a consequence, the historical results of operations for the periods presented may not be comparable.

The Partnership's Midstream segment margins are determined primarily by the volumes of natural gas gathered, transported, purchased and sold through its pipeline systems, processed at its processing facilities and the volumes of natural gas liquids handled at its fractionation facilities. Treating segment margins are largely a function of the number and size of treating plants as well as fees earned for removing impurities and from natural gas liquids at a non-operated processing plant. The Partnership generates revenues from five primary sources:

- purchasing and reselling or transporting natural gas on the pipeline systems it owns;
- processing natural gas at its processing plants and fractionating and marketing the recovered natural gas liquids;
- treating natural gas at its treating plants;
- recovering carbon dioxide and natural gas liquids at a non-operated processing plant; and
- providing off-system marketing services for producers.

The bulk of the Partnership's operating profits are derived from the margins it realizes for purchasing and reselling natural gas through its pipeline systems. Generally, the Partnership buys gas from a producer, plant tailgate, or transporter at either a fixed discount to a market index or a percentage of the market index. The Partnership then transports and resells the gas. The resale price is generally based on the same index price at which the gas was purchased, and, if the Partnership is to be profitable, at a smaller discount or larger premium to the index than it was purchased. The Partnership attempts to execute all purchases and sales substantially concurrently, or it enters into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. The Partnership's gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas. See "Commodity Price Risk" below for a discussion of how it manages its business to reduce the impact of price volatility.

Processing and fractionation revenues are largely fee based. 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 per unit of product.

The Partnership generates treating revenues under three arrangements:

- a volumetric fee based on the amount of gas treated, which accounted for approximately 48% and 51% of the operating income in the Treating division for the years ended December 31, 2006 and 2005, respectively;
- a fixed fee for operating the plant for a certain period, which accounted for approximately 32% and 38% of the operating income in the Treating division for the years ended December 31, 2006 and 2005, respectively; or
- a fee arrangement in which the producer operates the plant, which accounted for approximately 20% and 11% of the operating income in the Treating division for the years ended December 31, 2006 and 2005, 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.

Acquisitions

The Partnership has grown significantly through asset purchases 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 1, 2003, are the acquisitions of the Chief midstream assets, the South Louisiana Processing Assets and the LIG Pipeline Company. It also acquired treating operations totaling $16.0 million and $58.0 million during 2005 and 2006, respectively.

On June 29, 2006, the Partnership acquired the natural gas gathering pipeline systems and related facilities of Chief in the Barnett Shale for $475.3 million. The acquired systems consist of approximately 250 miles of existing pipeline with up to an additional 400 miles of planned pipelines, located in Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties, all of which are located in Texas. The acquired assets also include a 125 MMcf/d carbon dioxide treating plant and compression facilities with 26,000 horsepower. At closing, approximately 160,000 net acres previously owned by Chief and acquired by Devon simultaneously with the Partnership's acquisition, as well as 60,000 net acres owned by other producers, were dedicated to the systems. As of December 31, 2006, the Partnership had installed approximately 49 miles of gathering pipeline and connected 85 new wells to its gathering systems, 46 of which are owned or controlled by Devon and 39 of which are owned or controlled by other producers. In addition to expanding its gathering system, the Partnership had installed 4,400 horsepower of additional compression to handle the increased volumes. The Partnership also installed a new 55,000 Mcf/d cryogenic processing plant, referred to as its Azle plant, and added inlet refrigeration to an existing 30,000 Mcf/d plant in order to remove hydrocarbon liquids from growing gas streams. The Partnership has increased total throughput on this gathering system from approximately 115 MMcf/d at the time of the acquisition to 230 MMcf/d for the month of December 2006.

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

On October 3, 2006, the Partnership acquired the amine-treating business of Cardinal Gas Solutions Limited Partnership for $6.3 million. The acquisition added 10 dew point control plants and seven amine-treating plants to our plant portfolio.

On November 1, 2005, the Partnership acquired El Paso's processing and liquids business in South Louisiana for $481.0 million. The assets acquired include 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. The primary facilities and other assets acquired consist of: (1) the Eunice processing plant and fractionation facility; (2) the Pelican processing plant; (3) the Sabine Pass processing plant; (4) a 23.85% interest in the Blue Water gas processing plant; (5) the Riverside fractionator and loading facility; (6) the Cajun Sibon pipeline; and (7) the Napoleonville NGL storage facility. In May 2006, the Partnership acquired an additional 35.42% interest in the Blue Water gas processing plant for $16.5 million and became the operator of the plant.

On January 2, 2005, the Partnership acquired all of the assets of Graco Operations for $9.3 million. Graco's assets consisted of 26 treating plants and associated inventory. On May 1, 2005, it acquired all of the assets of Cardinal Gas Services for $6.7 million. Cardinal's assets consisted of nine gas treating plants, 19 dew point control plants and equipment inventory.

In April 2004 the Partnership acquired LIG Pipeline Company and its subsidiaries from a subsidiary of American Electric Power (AEP) for $73.7 million in cash. The principal assets acquired consist of approximately 2,000 miles of gas gathering and transmission systems located in 32 parishes extending from northwest and north-central Louisiana through the center of the state to the south and southeast Louisiana and two operating processing plants, with total processing capacity of 335,000 MMBtu/d. Average throughput at the time of our acquisition was approximately 560,000 MMBtu/d. Customers include power plants, municipal gas systems, and industrial markets located principally in the industrial corridor between New Orleans and Baton Rouge. The LIG system is connected to several interconnected pipelines and the Jefferson Island Storage facility providing access to additional system supply.

Other Assets

We own two inactive gas plants and a receivable associated with the Enron Corp. bankruptcy, which was collected in 2006, in addition to our limited and general partner interests in the Partnership. The two gas plants are the Jonesville processing plant, which has been largely inactive since the beginning of 2001, and the Clarkson plant, acquired shortly before the Partnership's initial public offering. In the third quarter of 2004, we fully impaired our investment in the Jonesville plant. We collected $1.6 million in excess of the carrying value of the receivable from Enron during 2006 which is included in other income.

Impact of Federal Income Taxes

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

As of December 31, 2006 we have a net operating loss carryforward of $64.4 million for federal income taxes and state loss carryforwards of $24.1 million. We estimate that our net operating loss carryforward will be utilized to offset most of the federal taxable income during 2007 and 2008. In years after 2008, however, we do not expect to have this net operating loss carryforward to offset our income. As a result, we will have to pay tax on our federal taxable income at a maximum rate of 35.0% under current law. Thus, the amount of money available to make cash distributions to our stockholders will decrease markedly after we use all of our net operating loss carryforward.

Our use of this net operating loss carryforward will be limited if there is a greater than 50.0% change in our stock ownership over a three year period. However, we do not expect such a change in ownership to limit our utilization of carryforwards prior to their 20-year expiration period.

Commodity Price Risk

The Partnership's 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 the Partnership's 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 profitability since the purchase price of a portion of the gas the Partnership buys 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 the Partnership's principal gathering and transmission systems and for its producer services business for the year ended December 31, 2006.

	Year Ended December 31, 2006			
	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	141,635	6,384	148,019	—
South Texas system(1)	148,111	15,134	148,186	—
North Texas system	28,177	—	28,177	—
Other assets and activities(1)	78,921	3,205	73,105	—

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

The Partnership estimates that, due to the gas that it purchases at a percentage of index price, for each $0.50 per MMBtu increase or decrease in the price of natural gas, its gross margins increase or decrease by approximately $1.3 million on an annual basis (before consideration of hedge positions). As of December 31, 2006, it has hedged approximately 78% of its exposure to such fluctuations in natural gas prices for 2007 and approximately 70% of our exposure to such fluctuations for the first quarter of 2008. CELP expects to continue to hedge its exposure to gas prices when market opportunities appear attractive.

The Partnership processed approximately 70.4% of its volumes during 2006 at Eunice, Pelican, Sabine and Blue Water under "percent of proceeds" contracts, under which it receives as a fee a portion of the liquids produced, and 29.6% fixed fee per unit processed. Under percent of proceeds contracts, it is exposed to changes in the prices of NGLs. For the years 2007 and 2008, it has purchased puts or entered into forward sales covering all of its anticipated minimum share of NGLs production.

The Partnership's processing plants at Plaquemine and Gibson have a variety of processing contract structures. In general, the Partnership buys gas under keep-whole arrangements in which it bears the risk of processing, percentage-of-proceeds arrangements in which it receives 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 the Partnership has the ability to bypass certain volumes when processing is uneconomic, it can limit its exposure to adverse processing margins. During periods when processing margins are favorable, the Partnership can substantially increase the volumes it is processing.

For the year ended December 31, 2006, the Partnership purchased a small amount (approximately 5.1%) of the natural gas volumes on its Gregory system under contracts in which it was exposed to the risk of loss or gain in processing the natural gas. The Partnership purchased the remaining approximately 94.9% of the natural gas volumes on its Gregory system 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 its Gregory processing plant with no risk of loss or gain in processing the natural gas.

The Partnership owns 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 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 50% of the NGLs produced by the plant. Therefore, the Partnership has commodity price exposure due to variances in the prices of NGLs. During 2006, its share of NGLs totaled 5.4 million gallons at an average price of $1.03 per gallon. The Partnership executed forward sales on approximately 81% of its anticipated 2007 share of NGLs and approximately 40% of its share of NGLs for the first quarter of 2008.

Gas prices can also affect the Partnership's 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.

	Year Ended December 31, 2006	2005	2004
		(Dollars in millions)	
Midstream revenues	$ 3,073.1	$ 2,982.9	$ 1,948.0
Midstream purchased gas	(2,859.8)	(2,860.8)	(1,861.2)
Profits on energy trading activities	2.5	1.6	2.2
Midstream gross margin	215.8	123.7	89.0
Treating revenues	66.2	48.6	30.8
Treating purchased gas	(9.5)	(9.7)	(5.3)
Treating gross margin	56.7	38.9	25.5
Total gross margin	$ 272.5	$ 162.6	$ 114.5
Midstream Volumes (MMBtu/d):			
Gathering and transportation	1,450,000	1,222,000	1,289,000
Processing	1,938,000	1,825,000	425,000
Producer services	138,000	175,000	210,000
Treating Plants in Operation at Year End	160	112	74

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

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $215.8 million for the year ended December 31, 2006 compared to $123.7 million for the year ended December 31, 2005, an increase of $92.1 million, or 75%. 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 from El Paso 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 Holdings LLC 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 CCNG, Gregory and Gulf Coast systems contributed to an overall margin decrease in our southern region of $6.9 million.

The favorable processing margins the Partnership realized during 2006 at its South Louisiana Processing Assets, the Gibson plant and the Plaquemine plant may be higher than processing margins it may realize during 2007 and future periods if the NGL markets do not remain as strong as they were during 2006. As discussed above under *"— Commodity Price Risk"*, the Partnership receives a processing fee as a portion of liquids processed or a percentage of the liquids recovered on a substantial portion of the gas processed through these plants. During periods when processing margins are favorable, as existed during 2006, the Partnership experiences higher processing margins. The Partnership has the ability to bypass certain volumes when processing is uneconomic so it can limit its exposure to adverse processing margins but our processing margins will be lower during these periods.

In addition, the Partnership has the ability to buy gas from and to sell gas to various gas markets through our pipeline systems. During 2006 the Partnership was able to benefit from price differentials between the various gas markets by selling gas into markets with more favorable pricing thereby improving its Midstream gross margin. If these price differentials do not exist during 2007 and future periods, the Partnership's Midstream gross margin may be lower.

Treating gross margin was $56.7 million for the year ended December 31, 2006 compared to $38.9 million for the year ended December 31, 2005, an increase of $17.8 million, or 46%. Treating plants in service increased from 112 plants at December 2005 to 160 plants 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 operations acquired from Hanover also include providing field services for producers which 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 $56.8 million for the year ended December 31, 2005, an increase of $44.2 million, or 78%. An increase of $27.0 million in operating expenses was associated with the South Louisiana Processing Assets which were owned for a full year in 2006 and only two months in 2005. Other Midstream increases of $7.7 million were due to the commencement of operations of the NTP as well as the Chief acquisition. The growth in the number of treating plants in service increased operating expenses by $4.8 million. Engineering and other technical service support costs also increased $2.9 million due to our asset growth. The remaining increase of $1.9 million is due to increased costs on our other Midstream systems. Operating expenses included stock-based compensation expenses of $1.1 million and $0.4 million for the year ended December 31, 2006 and 2005, respectively.

General and Administrative Expenses. General and administrative expenses were $47.7 million for the year ended December 31, 2006 compared to $34.1 million for the year ended December 31, 2005, an increase of $13.6 million, or 40%. A substantial part of the increased expenses resulted from staffing related costs of $6.5 million. The staff additions associated with the requirements of the El Paso, Hanover and Chief acquisitions accounted for the majority of the $6.5 million increase. Audit, legal and other consulting fees, office rent, travel, training and other administrative expenses, which increased due to the Partnership's growth, accounted for $3.4 million of 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 $3.7 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. Gain on derivatives was $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 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 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 gain in 2006 primarily related to the sale of an inactive gas processing facility acquired as part of the South Louisiana Processing Assets. The gain in 2005 primarily related to the sale of an inactive gas processing facility acquired as part of the LIG acquisition.

Depreciation and Amortization. Depreciation and amortization expenses were $82.8 million for the year ended December 31, 2006 compared to $36.1 million for the year ended December 31, 2005, an increase of $46.7 million, or 130%. An increase of $28.7 million in depreciation expense was associated with the South Louisiana Processing Assets which were owned for a full year in 2006 and only two months in 2005. The acquisition of the north Texas gathering system from Chief, the commencement of operations of the NTP and the related developments in north Texas in 2006 increased depreciation expense by $9.6 million. The acquisition of the treating assets from Hanover in 2006 contributed an increase of $2.5 million and other new treating plants acquired and placed in service contributed an increase of $2.5 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 $51.0 million for the year ended December 31, 2006 compared to $15.3 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).

Other Income. Other income was $1.8 million for the year ended December 31, 2006 compared to $0.4 million for the year ended December 31, 2005 because in 2006 we collected $1.6 million in excess of the carrying value of the Enron account receivable net of the allowance.

Gain on Issuance of Units of the Partnership. As a result of the Partnership issuing senior subordinated units in June 2005 to unrelated parties at a price per unit greater than our equivalent carrying value, our share of net assets of the Partnership increased by $19.0 million. We recognized the $19.0 million gain associated with the unit issuance in February 2006 when the senior subordinated units converted to common units. We recognized a gain of $65.1 million during 2005 associated with the Partnership's issuance of common units in November 2005.

Income Taxes. We provide income taxes using the liability method. Accordingly, deferred taxes are recorded for the differences between the tax and book basis of assets and liabilities that will reverse in future periods. Income tax expense was $11.1 million for the year ended December 31, 2006 compared to $30.0 million for the year ended December 31, 2005, a decrease of $18.9 million. The decrease in the gain on issuance of units of the Partnership from $65.1 million during 2005 to $19.0 million during 2006 is the primary reason for the decrease in income taxes between years. Income after minority interest also decreased $5.7 million between years which also reduced the income tax expense between years.

Interest of Non-Controlling Partners in the Partnership's Net Income. The interest of non-controlling partners in the Partnership's net income decreased by $17.7 million to a loss of $13.0 million for the year ended December 31, 2006 compared to income of $4.7 million for the year ended December 31, 2005 due to the changes shown in the following summary (in thousands):

	For the Year Ended December 31, 2006	For the Year Ended December 31, 2005
Net income for the Partnership	$ (4,191)	$ 19,200
(Income) allocation to CEI for the general partner incentive distribution	(20,422)	(10,660)
Stock-based compensation costs allocated to CEI for its stock options and restricted stock granted to Partnership officers, employees and directors	3,545	2,223
(Income)/loss allocation to CEI for its 2% general partner share of Partnership (income) loss	421	(215)
Net income (loss) allocable to limited partners	(20,647)	10,548
Less: CEI's share of net (income) loss allocable to limited partners	7,389	(6,337)
Plus: Non-controlling partners' share of net income (loss) in Crosstex Denton County Gathering, J.V.	231	441
Non-controlling partners' share of Partnership net income (loss)	$ (13,027)	$ 4,652

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

Cumulative Effect of Accounting Change. We recorded a $0.2 million cumulative adjustment to recognize the required change in reporting stock-based compensation under FASB Statement No. 123R which was effective January 1, 2006. The cumulative effect of this change is reported in our income net of taxes and non-controlling partners' interest.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $123.7 million for the year ended December 31, 2005 compared to $89.0 million for the year ended December 31, 2004, an increase of $34.7 million, or 39%. This increase was primarily due to acquisitions, volatile prices in the last half of the year and operational improvements on existing systems.

The acquisition of the South Louisiana Processing Assets contributed $14.1 million in the fourth quarter of 2005. The acquisition of the LIG assets on April 1, 2004 contributed $6.3 million to midstream gross margin in 2005 in our first full year of ownership. In addition, the acquisition of all outside interests in Crosstex Pipeline Partners, Ltd., as of December 31, 2004 accounted for a gross margin increase of $1.7 million. Relatively high and volatile natural gas prices during the quarters created favorable margin opportunities on several systems, offset by the negative impact on processing margins of high gas prices, as certain gas was no longer economical to process. The impact of these high and volatile gas prices on midstream operations was a gross margin increase of $5.4 million. During the fourth quarter, decline in gas prices created an imbalance gain of $4.5 million and made processing more profitable. Operational improvements and volume increases contributed margin growth of $5.1 million on the Vanderbilt, Denton County and Arkoma systems. In addition, the Gregory gathering system had a margin increase of $1.7 million primarily due to two measurement disputes which were settled during the year.

Treating gross margin was $38.9 million for the year ended December 31, 2005 compared to $25.5 million in the same period in 2004, an increase of $13.4 million, or 53%. The increase in treating plants in service from 74 plants at December 31, 2004 to 112 plants at December 31, 2005 contributed approximately $7.1 million in gross margin. Existing plant assets contributed $5.0 million in gross margin growth due primarily to plant expansion projects and increased volumes. The acquisition and installation of dew point control plants in 2005 contributed an additional $0.6 million to gross margin.

Operating Expenses. Operating expenses were $56.8 million for the year ended December 31, 2005 compared to $38.4 million for the year ended December 31, 2004, an increase of $18.4 million, or 48%. An increase of $5.3 million was associated with the acquisition of the South Louisiana Processing Assets from El Paso. LIG assets added $4.6 million of variance due to the fact that the assets were part of our business for the entire year in 2005 as opposed to nine months in 2004. Midstream operating expenses also increased by $2.6 million due to small acquisitions, expansions of systems and the addition of compressors or other rental services. The growth in treating plants in service due to acquisition of the Graco assets and the Cardinal assets as well as internal growth increased operating expenses by $5.2 million. Operations expense includes stock-based compensation expense of $0.4 million and $0.2 million in 2005 and 2004, respectively.

General and Administrative Expenses. General and administrative expenses were $34.1 million for the year ended December 31, 2005, compared to $22.0 million for the year ended December 31, 2004, an increase of $12.1 million, or 55%. A significant contributor was additional staffing-related costs, an incremental $6.0 million over 2004. The staff additions required to manage and optimize our acquisitions account for the majority of the change, although a number of leadership and strategic positions were added that will allow us to absorb future growth more efficiently. Other expenses related to growth, including office rent, utilities, and travel expenses, accounted for $2.6 million of the increase. General and administrative expense includes stock-based compensation expense of $3.7 million in 2005 and $0.8 million in 2004. The increase in stock-based compensation primarily relates to restricted stock and unit grants and $0.4 million in accelerated options.

(Gain) Loss on Derivatives. We had a loss on derivatives of $10.0 million for the year ended December 31, 2005 compared to a gain on derivatives of $0.3 million for the year ended December 31, 2004. The loss in 2005 includes a $9.2 million loss on puts acquired in the third quarter of 2005 related to the acquisition of the South Louisiana Processing Assets and a loss of $0.7 million associated with derivatives for the third-party on-system financial transactions and storage financial transactions primarily due to higher commodity prices at year end. As part of the overall risk management plan related to the November 2005 acquisition of the South Louisiana Processing Assets, 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. In December 2005 the Partnership sold a portion of these puts for $4.3 million. These puts were not designated as hedges as of December 31, 2005 and were marked to market through our consolidated statement of operations. The puts represent options, but not the obligation, to sell the related underlying liquids volumes at a fixed price. As the price of the underlying liquids increased significantly in the period, the value of the puts declined, which is reflected in gain/loss on derivatives.

Gain on Sale of Property. During 2005, the Partnership sold an inactive gas processing facility acquired as part of the LIG acquisition, which accounted for a substantial part of the $8.1 million gain on sale of property.

Depreciation and Amortization. Depreciation and amortization expenses were $36.1 million for the year ended December 31, 2005 compared to $23.0 million for the year ended December 31, 2004, an increase of $13.1 million, or 57%. Of the increase, the acquisition of the south Louisiana processing assets contributed $5.5 million and the LIG assets contributed $1.3 million. New treating plants placed in service resulted in an increase of $2.3 million. The remaining $3.9 million increase in depreciation and amortization is a result of expansion projects and other new assets, including the expansion of the Dallas office, computer software and equipment, and expansions on midstream assets.

Interest Expense. Interest expense was $15.3 million for the year ended December 31, 2005 compared to $9.1 million for the year ended December 31, 2004, an increase of $6.2 million, or 68%. The increase relates primarily to an increase in average debt outstanding. Average higher interest rates also increased from 2004 to 2005 (weighted average rate of 6.1% in 2004 compared to 6.3% in 2005).

Other Income. Other income was $0.4 million for the year ended December 31, 2005 compared to $0.8 million for the year ended December 31, 2004. Other income in 2004 includes $0.3 million related to a reimbursement for a construction project in excess of our costs for such project.

Gain on Issuance of Units of the Partnership. Principally as a result of the Partnership issuing the senior subordinated series B units and the public offering of common units, both of which happened in November 2005, our share of the net assets of the Partnership increased by $65.1 million. Accordingly, we recognized a $65.1 million gain in 2005.

Income Tax Expense. Our income tax provision was $30.1 million in 2005 compared to $5.1 million in 2004, an increase of $25.0 million. The increase in the tax provision was primarily due to the taxes provided on the $65.1 million gain on issuance of units of the Partnership during 2005.

Interest of Non-controlling Partners in the Partnership's Net Income. The interest of non-controlling partners in the Partnership's net income decreased by $3.6 million to income of $4.7 million for the year ended December 31, 2005 compared to income of $8.2 million for the year ended December 31, 2004 due to the changes show in the following summary:

	For the Year Ended December 31, 2005	2004
	(In thousands)	
Net income for the Partnership	$ 19,200	$ 23,704
(Income) allocation to CEI for the general partner incentive distribution	(10,660)	(5,550)
Stock-based compensation costs allocated to CEI for its stock options and restricted stock granted to Partnership officers, employees and directors	2,223	—
(Income) allocation to CEI for its 2% general partner share of Partnership (income)	(215)	(363)
Net income allocable to limited partners	10,548	17,791
Less: CEI's share of net (income) allocable to limited partners	(6,337)	(9,841)
Plus: Non-controlling partners' share of net income in Crosstex Denton County Gathering, J.V.	441	289
Non-controlling partners' share of Partnership net income	$ 4,652	$ 8,239

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

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. For further details on our accounting policies and a discussion of new accounting pronouncements, see Note 2 of the Notes to Consolidated Financial Statements.

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.

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

Prior to January 1, 2001, financial instruments which qualified for hedge accounting were accounted for using the deferral method of accounting, whereby unrealized gains and losses were generally not recognized until the physical delivery required by the contracts was made.

Effective January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133 ("SFAS No. 133"), *Accounting for Derivative Instruments and Hedging Activities.* In accordance with SFAS No. 133, all derivatives and hedging instruments are recognized as assets or liabilities at fair value. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

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

The Partnership manages its price risk related to future physical purchase or sale commitments for its Commercial Services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance the Company's future commitments and significantly reduce its risk to the movement in natural gas prices. However, the Company is subject to counterparty risk for both the physical and financial contracts. Prior to October 26, 2002, the Company accounted for its Commercial Services natural gas marketing activities as energy trading contracts in accordance with EITF 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* EITF 98-10 required energy-trading contracts to be recorded at fair value with changes in fair value reported in earnings. In October 2002, the EITF reached a consensus to rescind EITF No. 98-10. Accordingly, energy trading contracts entered into subsequent to October 25, 2002, should be accounted for under accrual accounting rather than mark-to-market accounting unless the contracts meet the requirements of a derivative under SFAS No. 133. The Company's energy trading contracts qualify as derivatives, and accordingly, the Company continues to use mark-to-market accounting for both physical and financial contracts of its Commercial Services business. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to the Company's Commercial Services natural gas marketing activities are recognized in earnings as profit or loss on energy trading immediately.

For each reporting period, the Partnership records the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period in addition to the realized gains or losses on settled activities are reported as profit or loss on energy trading activities in the statements of operations.

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

Impairment of Long-Lived Assets. In accordance with Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, 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;
- the Partnership's ability to negotiate favorable sales agreements;
- the risks that natural gas exploration and production activities will not occur or be successful;
- the Partnership's dependence on certain significant customers, producers, and transporters of natural gas; and
- competition from other midstream companies, including major energy producers.

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

Liquidity and Capital Resources

Cash Flows. Net cash provided by operating activities was $113.8 million for the year ended December 31, 2006 compared to cash provided by operations of $12.8 million for the year ended December 31, 2005. Income before non-cash income and expenses was $88.2 million in 2006 and $61.7 million in 2005. Changes in working capital provided $25.3 million in cash flows from operating activities in 2006 and used $48.9 million in cash flows from operating activities in 2005. Income before non-cash income and expenses increased between years primarily due to asset acquisitions, as discussed in "Results of Operations — Year Ended December 31, 2006 Compared to Year Ended December 31, 2005." Changes in working capital are primarily due to the timing of collections at the end of the quarterly periods. The Partnership collects and pays large receivables and payables at the end of each calendar month and the timing of these payments and receipts may vary by a day or two between month-end periods, causing these fluctuations.

Net cash used in investing activities was $885.8 million and $614.8 million for the year ended December 31, 2006 and 2005, respectively. Net cash used in investing activities during 2006 related to the $504.7 million Chief acquisition ($474.9 million paid to Chief, $0.4 million of direct acquisition costs and $29.4 million for assumed capital expenditure liabilities paid by us after acquisition), the $51.7 million Hanover acquisition, the $16.5 million acquisition of our additional interest in the Blue Water processing plant and the $6.3 million Cardinal Gas Solutions acquisition. Costs for the year ended December 31, 2006 associated with the pipeline and processing plant construction, the connection of new wells to various systems, pipeline integrity projects, pipeline relocations and various other internal growth projects totaled $314.9 million. The most significant projects included in 2006 costs were the construction of the NTP of $48.2 million, construction of a processing plant in Parker County for the North Texas Assets of $76.1 million, the construction of the North Louisiana Pipeline expansion of $38.5 million and the expansion of the North Texas Assets acquired from Chief of $31.0 million. Net cash used in investing activities during 2005 related to the acquisition of the El Paso assets ($489.4 million), the Graco assets ($9.3 million) and the Cardinal assets ($6.7 million). The remaining cash used in investing activities for 2005 related to internal growth projects including expenditures of the approximately $80.0 million for the NTP project, $21.2 million for buying, refurbishing and installing treating plants and $19.9 million for expansions, well connections and other capital projects on the pipeline, gathering and processing assets.

Net cash provided by financing activities was $769.7 million and $592.4 million for the years ended December 31, 2006 and 2005, respectively. Financing activities for 2006 related to equity from issuance of common stock of $179.7 million, net proceeds from issuance of Partnership units of $179.2 million, net borrowings under the Partnership's amended credit facility of $166.0 million and net borrowings under the Partnership's senior secured notes of $298.5 million. We paid dividends on our common stock of $34.7 million in the year ended December 31, 2006 compared to $21.6 million in the year ended December 31, 2005. Distributions to non-controlling partners in the Partnership totaled $34.5 million in 2006 compared to distributions of $15.2 million in 2005 due to increases in the distribution levels between years and due to increases in the number of units outstanding. Drafts payable increased by $18.1 million providing cash in 2006 compared to a decrease in drafts payable of $8.8 million requiring use of cash in 2005. In order to reduce its interest costs, the Partnership borrows money to fund outstanding checks as they are presented to the bank. Fluctuations in drafts payable are caused by timing of disbursements, cash receipts and draws on the Partnership's revolving credit facility.

Off-Balance Sheet Arrangements. We had no off-balance sheet arrangements as of December 31, 2006 and 2005.

June 2006 Sale of Senior Subordinated Series C Units. On June 29, 2006, the Partnership issued an aggregate of 12,829,650 senior subordinated series C units representing limited partner interests of the Partnership in a private equity offering for net proceeds of $359.3 million. The senior subordinated series C units were issued at $28.06 per unit, which represented a discount of 25% to the market value of common units on such date. We purchased 6,414,830 of the senior subordinated series C units. In addition, the Partnership's general partner made a contribution of $9.0 million in connection with the issuance to maintain its 2% general partner interest. The senior subordinated series C units will automatically convert to common units representing limited partner interests of the Partnership on the first date on or before February 16, 2008 that conversion is permitted by the Partnership's partnership agreement at a ratio of one common unit for each senior subordinated series C unit.

June 2006 Sale of Capital Stock. On June 29, 2006, we issued 7,650,780 shares of common stock in a private placement for total net proceeds of $179.9 million. Lubar Equity Fund, LLC, an affiliate of one of our directors, purchased 468,210 of the shares at a purchase price of $25.633 per share and unrelated third parties purchased 7,182,570 shares at a purchase price of $23.39 per share. We used the proceeds of stock issuance to purchase $180.0 million of senior subordinated series C units representing limited partner interests of the Partnership described in *"— June 2006 Issuance of Senior Subordinated Series C Units"* above.

November 2005 Sale of Senior Subordinated B Units. On November 1, 2005, the Partnership issued 2,850,165 senior subordinated series B units in a private placement for a purchase price of $36.84 per unit. The Partnership received net proceeds of approximately $107.1 million, including the $2.1 million capital contribution from its general partner and net of 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 and December 2005, the Partnership 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 the $2.5 million capital contribution from its general partner and net of expenses associated with the offering.

June 2005 Sale of Senior Subordinated Units. In June 2005, the Partnership issued 1,495,410 senior subordinated units in a private equity offering for net proceeds of $51.1 million, including our $1.1 million capital contribution. 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.

Bank Credit Facility. On June 29, 2006, the Partnership amended its bank credit facility increasing availability under the facility to $1.0 billion. The bank credit agreement includes procedures for additional financial institutions selected by the Partnership to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by the Partnership and the lender, subject to a maximum of $300.0 million for all such increases in commitments of new or existing lenders. The maturity date was also extended to June 2011.

Senior Secured Notes. In March 2006, the Partnership issued $60.0 million aggregate principal amount of senior secured notes with an interest rate of 6.32% and a maturity of ten years. In July 2006, the Partnership issued

$245.0 million aggregate principal amount of senior secured notes with an interest rate of 6.96% and a maturity of ten years.

Capital Requirements of the Partnership. The natural gas gathering, transmission, treating and processing businesses are capital-intensive, requiring significant investment to maintain and upgrade existing operations. The Partnership's capital requirements have consisted primarily of, and it anticipates will continue to be:

- maintenance capital expenditures, which are capital expenditures made to replace partially or fully depreciated assets in order to maintain existing operating capacity of the Partnership's assets and to extend their useful lives, or other capital expenditures which do not increase the Partnership's cash flows; and
- growth capital expenditures such as those to acquire additional assets to grow the Partnership's 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.

Given the Partnership's objective of growth through acquisitions and large capital expansions, it anticipates that it will continue to invest significant amounts of capital to grow and to build and acquire assets. The Partnership actively considers a variety of assets for potential development or acquisition.

The Partnership believes that cash generated from operations will be sufficient to meet its present quarterly distribution level of $0.56 per quarter and to fund a portion of its anticipated capital expenditures through December 31, 2006. Total capital expenditures are budgeted to be approximately $260.0 million in 2007. The Partnership expects to fund the remaining capital expenditures from the proceeds of borrowings under the revolving credit facility discussed below and with future issuances of units. The Partnership's ability to pay distributions to its unit holders and to fund planned capital expenditures and to make acquisitions will depend upon its future operating performance, which will be affected by prevailing economic conditions in its industry and financial, business and other factors, some of which are beyond its control.

Total Contractual Cash Obligations. A summary of the Partnership's total contractual cash obligations as of December 31, 2006, is as follows:

	Payments Due by Period						
	Total	2007	2008	2009	2010	2011	Thereafter
				(In millions)			
Long-Term Debt	$ 987.1	$ 10.0	$ 9.4	$ 9.4	$ 20.3	$ 520.0	$ 418.0
Capital Lease Obligations	—	—	—	—	—	—	—
Operating Leases	103.2	18.7	17.8	17.1	16.0	16.0	17.6
Unconditional Purchase Obligations	4.6	4.6	—	—	—	—	—
Other Long-Term Obligations	—	—	—	—	—	—	—
Total Contractual Obligations	$ 1,094.9	$ 33.3	$ 27.2	$ 26.5	$ 36.3	$ 536.0	$ 435.6

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

The unconditional purchase obligations for 2007 relate to purchase commitments for equipment. The Partnership has also committed to contract for 150,000 MMBtus/day 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.

Description of Indebtedness

As of December 31, 2006 and 2005, long-term debt consisted of the following:

	2006	2005
	(In thousands)	
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2006 and 2005 were 7.20% and 6.69%, respectively	$ 488,000	$ 322,000
Senior secured notes, weighted average interest rate of 6.76% and 6.64%, respectively	498,530	200,000
Note payable to Florida Gas Transmission Company	600	650
	987,130	522,650
Less current portion	(10,012)	(6,521)
Debt classified as long-term	$ 977,118	$ 516,129

On June 29, 2006, the Partnership amended its bank credit facility, increasing availability under the facility to $1.0 billion and extending the maturity date from November 2010 to June 2011. The bank credit agreement includes procedures for additional financial institutions selected by the Partnership to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by the Partnership and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders.

The credit facility was used for the El Paso, Chief and Hanover acquisitions and will be used to finance the acquisition and development of gas gathering, treating, and processing facilities, as well as general partnership purposes. At December 31, 2006, $564.3 million was outstanding under the credit facility, including $76.3 million of letters of credit, leaving approximately $453.7 available for future borrowings. The credit facility will mature in June 2011, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the credit facility may be re-borrowed.

The obligations under the bank credit facility are secured by first priority liens on all of the Partnership's material pipeline, gas gathering, treating, and processing assets, all material working capital assets and a pledge of all of its 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 and by the Partnership. The Partnership may prepay all loans under the bank 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 its 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 based on the unused amount of the credit facilities. The amendment to the credit facility also adjusted financial covenants requiring the Partnership to maintain:

- an initial ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of 5.25 to 1.00, pro forma for any asset acquisitions. The maximum leverage ratio is reduced to 4.75 to 1.00 beginning July 1, 2007 and further reduces to 4.25 to 1.00 on January 1, 2008. The maximum leverage ratio increases to 5.25 to 1.00 during an acquisition adjustment period, as defined in the credit agreement; and
- 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.

Additionally, the bank credit facility was amended to allow for borrowings under the Partnership's senior secured note shelf agreement to increase from $260 million to $510 million.

The credit agreement prohibits the Partnership from declaring distributions to unitholders 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 its or the operating partnership's partnership agreement; and
- engage in transactions with affiliates.

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

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to observe any agreement, obligation, or covenant in the credit agreement, subject to cure periods for certain failures;
- certain judgments against the Partnership or any of its subsidiaries, in excess of certain allowances;
- certain ERISA events involving the Partnership or its subsidiaries;
- cross defaults to certain material indebtedness;
- certain bankruptcy or insolvency events involving the Partnership or its 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.

In November 2006, the Partnership entered into an interest rate swap covering a principal amount of $50.0 million in the credit facility for a period of three years. The Partnership is subject to interest rate risk on its credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 4.95%, on $50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. The Partnership has elected not to designate this swap as a cash flow hedge for FAS 133 accounting treatment. Accordingly, unrealized gains or losses relating to the swap flow through the Consolidated Statement of Operations as adjustments to interest expense over the period hedged. The fair value of the interest rate swap at December 31, 2006 was a $0.1 million asset.

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, to $510.0 million, pursuant to which the Partnership issued the following senior secured notes:

Month Issued	Amount (In thousands)	Interest Rate	Maturity
June 2003	$ 30,000	6.95%	7 years
July 2003	10,000	6.88%	7 years
June 2004	75,000	6.96%	10 years
November 2005	85,000	6.23%	10 years
March 2006	60,000	6.32%	10 years
July 2006	245,000	6.96%	10 years
Total issued	505,000		
Principal repaid	(6,470)		
Balance as of December 31, 2006	$ 498,530		

These notes represent senior secured obligations 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 the Partnership's obligations under the credit facility, by first priority liens on all of its material pipeline, gas gathering and processing assets, all material working capital assets and a pledge of all of its equity interests in certain of its subsidiaries. The senior secured notes are guaranteed by the Partnership and its significant 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 in 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance. During 2007 the notes may also incur an additional fee each quarter ranging from 0.08% to 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 more than 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 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, 2006 and 2005 and expects to be in compliance for the next twelve months.

Intercreditor and Collateral Agency Agreement. In connection with the execution of the master shelf agreement in June 2003, the lenders under the bank credit facility and the initial purchasers of the senior secured notes entered into an Intercreditor and Collateral Agency Agreement, which was acknowledged and agreed to by the Partnership's operating partnership and its subsidiaries. As amended in 2005, this agreement appoints Bank of America, N.A. to act as collateral agent and authorized the bank to execute various security documents on behalf of the lenders under the bank credit facility and the purchases 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 Crosstex Energy Services, L.P.'s obligations under the bank credit facility and the master shelf agreement.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2004, 2005 or 2006. 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 the Partnership's existing agreements, it has and will continue to pass along increased costs to our customers in the form of higher fees.

Environmental and Other Contingencies

The Partnership's operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. The Partnership believes it is in material compliance with all applicable laws and regulations. For a more complete discussion of the environmental laws and regulations that impact us. See Item 1. "Business — Environmental Matters."

Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board, or FASB, issued FASB Interpretation No. 48 ("FIN 48"), *"Accounting for Uncertainty in Income Taxes".* FIN 48 is an interpretation of FASB Statement No. 109, *"Accounting for Income Taxes"* and must be adopted no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions taken or expected to be taken.

On September 13, 2006, the Securities Exchange Commission, or 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.

Disclosure Regarding Forward-Looking Statements

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

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

Market risk is the risk of loss arising from adverse changes in market rates and prices. The Partnership's primary market risk is the risk related to changes in the prices of natural gas and natural gas liquids. In addition, it is also exposed to the risk of changes in interest rates on its floating rate debt.

Interest Rate Risk

The Partnership is exposed to interest rate risk on short-term and long-term debt carrying variable interest rates. At December 31, 2006 and 2005, the Partnership's variable rate debt had a carrying value of $488.6 million and $322.7 million, respectively, which approximated its fair value, and the Partnership's fixed rate debt had a carrying value of $498.5 million and $200.0 million, respectively, and an approximately fair value of $503.9 million and $203.9 million, respectively. The Partnership attempts to balance variable rate debt, fixed rate debt and debt maturities to manage interest cost, interest rate volatility and financing risk. This is accomplished through a mix of bank debt with short-term variable rates and fixed rate senior and subordinated debt. In addition, the Partnership entered into an interest rate swap in November 2006 covering $50.0 million of the variable rate debt for a period of three years.

The following table shows the carrying amount and fair value of long-term debt and the hypothetical change in fair value that would result from a 100-basis point change in interest rates. Unless otherwise noted, the hypothetical change in fair value could be a gain or a loss depending on whether interest rates increase or decrease.

	Carrying Amount	Fair Value(a)	Hypothetical Change in Fair Value
		(In millions)	
December 31, 2006 Long-term debt	$ (987.1)	$ (996.9)	$ 9.8
December 31, 2005 Long-term debt	$ (522.7)	$ (529.8)	$ 7.1

(a) Fair value is based upon current market quotes and is the estimated amount required to purchase our long-term debt on the open market. This estimated value does not include any redemption premium.

Commodity Price Risk

Approximately 5.9% of the natural gas the Partnership markets is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, the Partnership's resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices. As of December 31, 2006, the Partnership has hedged approximately 78% of its exposure to natural gas price fluctuations through December 2007 and approximately 70% of its exposure to gas price fluctuations for the first quarter of 2008. The Partnership also has hedges in place covering at least 100% of the minimum liquid volumes it expects to receive through the end of 2007 and approximately 25% for the first quarter of 2008 at its south Louisiana assets, and 81% of the liquids at its other assets in 2007 and 40% for the first quarter of 2008.

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

The Partnership has commodity price risk associated with its processed volumes of natural gas. The Partnership currently processes gas under four main types of contractual arrangements:

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

2. Percent of proceeds contracts: Under these contracts, The Partnership receives a fee in the form of a percentage of the liquids recovered, and the producer bears all the cost of the natural gas shrink. Therefore, its margins from these contracts are greater during periods of high liquids prices. The Partnership's margins from

processing cannot become negative under percent of proceeds contracts, but decline during periods of low NGL prices.

3. Theoretical processing contracts: Under these contracts, the Partnership stipulates with the producer the assumptions under which it 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 the Partnership has no commodity price exposure, and is paid a fixed fee per unit of volume that is treated or conditioned.

The Partnership's primary commodity risk management objective is to reduce volatility in its cash flows. The Partnership maintains a Risk Management Committee, including members of senior management, which oversees all hedging activity. The Partnership enters into hedges for natural gas and NGLs using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by its Risk Management Committee.

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

The Partnership manages its price risk related to future physical purchase or sale commitments for its producer services activities by entering into either corresponding physical delivery contracts or financial instruments with an objective to balance its future commitments and significantly reduce its risk to the movement in natural gas prices. However, the Partnership is subject to counterparty risk for both the physical and financial contracts. The Partnership accounts for certain of its producer services natural gas marketing activities as energy trading contracts or derivatives. These energy-trading contracts are recorded at fair value with changes in fair value reported in earnings. Accordingly, any gain or loss associated with changes in the fair value of derivatives and physical delivery contracts relating to its producer services natural gas marketing activities are recognized in earnings as profit or loss on energy trading contracts immediately.

For each reporting period, we record the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period is reported as a gain or loss on derivatives in the statement of operations. Realized gains and losses from settled contracts accounted for as cash flow hedges are recorded in Midstream Revenue. As of December 31, 2006, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $10.4 million, excluding the fair value asset of $1.7 million associated with the natural gas liquids puts. The aggregate effect of a hypothetical 10% increase in gas and NGLs prices would result in a decrease of approximately $4.8 million in the net fair value asset of these contracts as of December 31, 2006. The value of the natural gas liquids puts would also decrease as a result of an increase in NGLs prices but we are unable to determine the impact of a 10% price change. Our maximum loss on these puts is the remaining $1.7 million recorded fair value for the puts.

Credit Risk

The Partnership is diligent in attempting to ensure that it issues credit to only credit-worthy customers. However, its purchase and resale of gas exposes it to significant credit risk, as the margin on any sale is generally a very small percentage of the total sale price. Therefore, a credit loss can be very large relative to the Partnership's overall profitability.

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-46 of this Report and are incorporated herein by reference.

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

None.

Item 9A. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the design and operating effectiveness of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Exchange Act Rules 13a-15 and 15d-15. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2006 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, 2006 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***

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

Name	Age	Position with Crosstex Energy GP, LLC
Barry E. Davis(1)	45	President, Chief Executive Officer and Director
Robert S. Purgason	50	Executive Vice President — Chief Operating Officer
James R. Wales	53	Executive Vice President — Commercial
A. Chris Aulds	45	Executive Vice President — Public and Governmental Affairs
Jack M. Lafield	56	Executive Vice President — Corporate Development
William W. Davis(1)	53	Executive Vice President and Chief Financial Officer
Joe A. Davis(1)	46	Executive Vice President, General Counsel and Secretary
Danny Thompson	57	Senior Vice President — Engineering and Operations

(1) Not related.

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

Robert S. Purgason, Executive Vice President — Chief Operating Officer, joined Crosstex in October 2004 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.

James R. Wales, Executive Vice President Commercial, joined our predecessor in December 1996. As one of the founders of Sunrise Energy Services, Inc., he helped build Sunrise into a major national independent natural gas marketing company, with sales and service volumes in excess of 600,000 MMBtu/d. Mr. Wales started his career as an engineer with Union Carbide. In 1981, he joined Producers Gas Company, a subsidiary of Lear Petroleum Corp., and served as manager of its Mid-Continent office. In 1986, he joined Sunrise as Executive Vice President of Supply, Marketing and Transportation. From 1993 to 1994, Mr. Wales was the Chief Operating Officer of Triumph Natural Gas, Inc., a private midstream business. Prior to joining Crosstex, Mr. Wales was Vice President for Teco Gas Marketing Company. Mr. Wales holds a B.S. degree in Civil Engineering from the University of Michigan, and a Law degree from South Texas College of Law.

A. Chris Aulds, Executive Vice President Public and Governmental Affairs, together with Barry E. Davis, participated in the management buyout of Comstock Natural Gas in December 1996. Mr. Aulds joined Comstock Natural Gas, Inc. in October 1994 as a result of the acquisition by Comstock of the assets and operations of Victoria Gas Corporation. Mr. Aulds joined Victoria in 1990 as Vice President responsible for gas supply, marketing and new business development and was directly involved in the providing of risk management services to gas producers. Prior to joining Victoria, Mr. Aulds was employed by Mobil Oil Corporation as a production engineer before being transferred to Mobil’s gas marketing division in 1989. There he assisted in the creation and implementation of Mobil’s third- party gas supply business segment. Mr. Aulds holds a B.S. degree in Petroleum Engineering from Texas Tech University.

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, 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 25 years of finance and accounting experience. Prior to joining our predecessor, Mr. Davis held various positions with Sunshine Mining and Refining Company from 1983 to September 2001, including Vice President-Financial Analysis from 1983 to 1986, Senior Vice President and Chief Accounting Officer from 1986 to 1991 and Executive Vice President and Chief Financial Officer from 1991 to 2001. In addition, Mr. Davis served as Chief Operating Officer in 2000 and 2001. Mr. Davis graduated magna cum laude from Texas A&M University with a B.B.A. in Accounting and is a Certified Public Accountant.

Joe A. Davis, Executive Vice President, General Counsel and Secretary joined Crosstex in October 2005. He began his legal career with the Dallas firm of Worsham Forsythe, which merged with the international law firm of Hunton & Williams in 2002. Most recently, he served as a partner in the firm's Energy Practice Group, and served on the firm's Executive Committee. Mr. Davis specialized in facility development, sales, acquisitions and financing for the energy industry, representing entrepreneurial start up/development companies, growth companies, large public corporations and large electric and gas utilities. He received his J.D. from Baylor Law School in Waco and his bachelor of science from the University of Texas in Dallas.

Danny L. Thompson, Senior Vice President — Engineering and Operations, has held various leadership positions within the midstream energy industry. From March 2005 until August 2005 when he became an employee of Crosstex, he worked with Crosstex as a consultant. Prior to joining Crosstex, he worked for Cantera Natural Gas L.L.C. as vice president, operations and engineering and CMS Field Services as director of engineering and operations. Mr. Thompson holds a bachelor's degree in chemical engineering from Texas A&I University in Kingsville, and he is a registered professional engineer in Texas.

Code of Ethics

We adopted a Code of Business Conduct and Ethics applicable to all of our employees, including all officers, and including our independent directors, who are not employees, with regard to company-related activities. The Code of Business Conduct and Ethics incorporates guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. The Code also incorporates our expectations of our employees that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission and other public communications. A copy of our Code of Business Conduct and Ethics will be provided to any person, without charge, upon request. Contact Denise LeFevre at 214-721-9245 to request a copy of a charter or send your request to Crosstex Energy, Inc., Attn: Denise LeFevre, 2501 Cedar Springs, Dallas, Texas 75201. If any substantive amendments are made to the Code of Business Conduct and Ethics or if we grant any waiver, including any implicit waiver, from a provision of the code to any of our executive officers and directors, we will disclose the nature of such amendment or waiver in a report on Form 8-K.

Other

The sections entitled "Election of Directors", "Additional Information Regarding the Board of Directors", "Section 16(a) Beneficial Ownership Reporting Compliance", and "Stockholder Proposals and Other Matters" that appear in our proxy statement for the 2007 annual meeting of stockholders (see "2007 Proxy Statement"), set forth certain information with respect to our directors and with respect to reporting under Section 16(a) of the Securities Exchange Act of 1934, and are incorporated herein by reference.

Item 11. *Executive Compensation*

The section entitled "Executive Compensation" that appears in the 2007 Proxy Statement sets forth certain information with respect to the compensation of our management, and, except for the report of the Compensation Committee of our board of directors on executive compensation, is incorporated herein by reference.

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

The sections entitled "Security Ownership of Certain Beneficial Owners and Management" that appears in the 2007 Proxy Statement set forth certain information with respect to securities authorized for issuance under equity compensation plans and the ownership of voting securities and equity securities of us, and are incorporated herein by reference.

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

The section entitled "Certain Relationships and Related Party Transactions" that appears in the 2007 Proxy Statement sets forth certain information with respect to certain relationships and related party transactions, and is incorporated herein by reference.

Item 14. *Principal Accounting Fees and Services*

The section entitled "Auditors" that appears in the 2007 Proxy Statement sets forth certain information with respect to accounting fees and services, and is incorporated herein by reference.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) *Financial Statements and Schedules*

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

(2) See Schedule I — Parent Company Statements on page F-40 and Schedule II — Valuation and Qualifying Accounts on Page F-46.

(3) Exhibits

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

Number		Description
3.1	—	Amended and Restated Certificate of Incorporation of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006).
3.2	—	Third Amended and Restated Bylaws of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated March 22, 2006, filed with the Commission on March 28, 2006).
3.3	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Fifth Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of June 29, 2006 (incorporated by reference to Exhibit 3.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
3.5	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference from Exhibit 3.3 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.7	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference from Exhibit 3.6 to Crosstex Energy L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference from Exhibit 3.7 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.10	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference from Exhibit 3.8 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
3.11	—	Amended and Restated Certificate of Formation of Crosstex Holdings GP, LLC (incorporated by reference from Exhibit 3.11 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.12	—	Limited Liability Company Agreement of Crosstex Holdings GP, LLC, dated as of October 27, 2003 (incorporated by reference from Exhibit 3.12 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).

Number		Description
3.13	—	Certificate of Formation of Crosstex Holdings LP, LLC (incorporated by reference from Exhibit 3.13 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.14	—	Limited Liability Company Agreement of Crosstex Holdings LP, LLC, dated as of November 4, 2003 (incorporated by reference from Exhibit 3.14 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.15	—	Amended and Restated Certificate of Limited Partnership of Crosstex Holdings, L.P. (incorporated by reference from Exhibit 3.15 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.16	—	Agreement of Limited Partnership of Crosstex Holdings, L.P., dated as of November 4, 2003 (incorporated by reference from Exhibit 3.16 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
4.1	—	Specimen Certificate representing shares of common stock (incorporated by reference from Exhibit 4.1 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
4.2	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy, Inc., Chieftain Capital Management, Inc., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LB I Group Inc., Lubar Equity Fund, LLC and Tortoise North American Energy Corp. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.1	—	Omnibus Agreement dated December 17, 2002, among Crosstex Energy, Inc. and certain other parties (incorporated by reference from Exhibit 10.5 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.2†	—	Form of Indemnity Agreement (incorporated by reference from Exhibit 10.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.3†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan dated July 12, 2002 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, L.P.'s Annual Report on Form 10-K, file No. 000-50067).
10.4†	—	Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.5	—	Agreement Regarding 2003 Registration Rights Agreement and Termination of Stockholders' Agreement, dated October 27, 2003 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.6†	—	Crosstex Energy, Inc. Amended and Restated Long-Term Incentive Plan effective as of September 6, 2006 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006).
10.7	—	Registration Rights Agreement, dated December 31, 2003 (incorporated by reference from Exhibit 10.6 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.8	—	Fourth Amended and Restated Credit Agreement, dated November 1, 2005, among Crosstex Energy Services, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.9	—	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).
10.10	—	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.11	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).

Number		Description
10.12	—	Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.13	—	Seminole Gas Processing Plant Gaines County, Texas Joint Operating Agreement dated January 1, 1993 (incorporated by reference to Exhibit 10.10 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
10.14	—	Stock Purchase Agreement, dated as of May 16, 2006, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated May 16, 2006, filed with the Commission on May 17, 2006).
10.15	—	Senior Subordinated Series C Unit Purchase Agreement, dated May 16, 2006, 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 May 16, 2006, filed with the Commission on May 17, 2006).
10.16	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy, L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LB I Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
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 28th day of February 2007.

CROSSTEX ENERGY, INC.

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ BARRY E. DAVIS Barry E. Davis	President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2007
/s/ FRANK M. BURKE Frank M. Burke	Director	February 28, 2007
/s/ JAMES C. CRAIN James C. Crain	Director	February 28, 2007
/s/ BRYAN H. LAWRENCE Bryan H. Lawrence	Chairman of the Board	February 28, 2007
/s/ SHELDON B. LUBAR Sheldon B. Lubar	Director	February 28, 2007
/s/ CECIL E. MARTIN Cecil E. Martin	Director	February 28, 2007
/s/ ROBERT F. MURCHISON Robert F. Murchison	Director	February 28, 2007
/s/ WILLIAM W. DAVIS William W. Davis	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 28, 2007

INDEX TO FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

In connection with the preparation of the Company's annual consolidate financial statements, management has undertaken an assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). Management's assessment included an evaluation of the design of the Company's internal control over financial reporting and testing of the operational effectiveness of those controls.

Based on this assessment, management has concluded that as of December 31, 2006, the Company's internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Crosstex Energy, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, changes in stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2006. In connection with our audits of the consolidated financial statements, we also have audited the accompanying financial statement schedules. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Crosstex Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations, comprehensive income, and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in note 2 to the consolidated financial statements, effective January 1, 2006, Crosstex Energy, Inc. 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 effectiveness of Crosstex Energy, Inc.'s internal control over financial reporting as of December 31, 2006, 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 28, 2007, expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Dallas, Texas
February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Crosstex Energy, Inc. and subsidiaries (a Delaware corporation) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and 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, management's assessment that Crosstex Energy, Inc. and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Crosstex Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, changes in stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2006, and our report dated February 28, 2007 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 28, 2007

CROSSTEX ENERGY, INC.

Consolidated Balance Sheets

	December 31, 2006	December 31, 2005
	(In thousands, except share data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 10,635	$ 12,904
Accounts receivable:		
Trade, net of allowance for bad debts of $618 and $260, respectively	35,787	60,067
Accrued revenues	331,236	368,860
Imbalances	5,159	7,834
Note receivable	926	845
Other	2,864	4,896
Fair value of derivative assets	23,048	12,205
Natural gas and natural gas liquids, prepaid expenses and other	10,574	28,772
Total current assets	420,229	496,383
Property and equipment:		
Transmission assets	335,599	194,235
Gathering systems	285,706	36,653
Gas plants	460,822	389,083
Other property and equipment	32,304	27,770
Construction in process	129,373	98,142
Total property and equipment	1,243,804	745,883
Accumulated depreciation	(136,562)	(77,251)
Total property and equipment, net	1,107,242	668,632
Account receivable from Enron	—	1,068
Fair value of derivative assets	3,812	7,633
Intangible assets, net of accumulated amortization of $31,673 and $7,674, respectively	638,602	255,197
Goodwill	25,396	7,570
Other assets, net	11,417	8,842
Total assets	$ 2,206,698	$ 1,445,325
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Drafts payable	$ 47,948	$ 29,855
Accounts payable	31,764	16,574
Accrued gas purchases	325,151	360,458
Accrued imbalances payable	2,855	30,515
Accrued construction in process costs	29,942	10,545
Fair value of derivative liabilities	12,141	14,782
Current portion of long-term debt	10,012	6,521
Other current liabilities	30,507	22,260
Total current liabilities	490,320	491,510
Fair value of derivative liabilities	2,558	3,577
Deferred tax liability	66,186	58,136
Long-term debt	977,118	516,129
Interest of non-controlling partners in the Partnership	391,103	241,726
Commitments and contingencies	—	—
Stockholders' equity:		
Common stock (150,000,000 shares authorized, $.01 par value, 45,941,187 and 12,760,158 issued and outstanding in 2006 and 2005, respectively)	463	127
Additional paid-in capital	263,264	80,187
Retained earnings	13,535	31,747
Accumulated other comprehensive income	2,151	(814)
Total stockholders' equity	279,413	111,247
Total liabilities and stockholders' equity	$ 2,206,698	$ 1,445,325

See accompanying notes to consolidated financial statements

CROSSTEX ENERGY, INC.

Consolidated Statements of Operations

	Years Ended December 31, 2006	2005	2004
	(In thousands, except per share data)		
Revenues:			
Midstream	$ 3,073,069	$ 2,982,874	$ 1,948,021
Treating	66,225	48,606	30,755
Profit on energy trading activities	2,510	1,568	2,228
Total revenues	3,141,804	3,033,048	1,981,004
Operating costs and expenses:			
Midstream purchased gas	2,859,815	2,860,823	1,861,204
Treating purchased gas	9,463	9,706	5,274
Operating expenses	101,036	56,768	38,396
General and administrative	47,707	34,145	22,005
Impairments	—	—	981
(Gain) loss on derivatives	(1,599)	9,968	(279)
Gain on sale of property	(2,108)	(8,138)	(12)
Depreciation and amortization	82,792	36,070	23,034
Total operating costs and expenses	3,097,106	2,999,342	1,950,603
Operating income	44,698	33,706	30,401
Other income (expense):			
Interest expense, net of interest income	(51,051)	(15,332)	(9,115)
Other income	1,774	391	802
Total other income (expense)	(49,277)	(14,941)	(8,313)
Income before gain on issuance of units by the Partnership, income taxes and interest of non-controlling partners in the Partnership's net income	(4,579)	18,765	22,088
Gain on issuance of units of the Partnership	18,955	65,070	—
Income tax provision	(11,118)	(30,047)	(5,149)
Interest of non-controlling partners in the Partnership's net income (loss)	13,027	(4,652)	(8,239)
Net income before cumulative effect of change in accounting principle	16,285	49,136	8,700
Cumulative effect of change in accounting principle	170	—	—
Net income	$ 16,455	$ 49,136	$ 8,700
Preferred stock dividends	—	—	$ 132
Net income available to common	$ 16,455	$ 49,136	$ 8,568
Net income before cumulative effect of change in accounting principle per common share:			
Basic	$ 0.39	$ 1.29	$ 0.24
Diluted	$ 0.39	$ 1.26	$ 0.22
Cumulative effect of change in accounting principle per common share:			
Basic	—	—	—
Diluted	—	—	—
Net income per common share:			
Basic	$ 0.39	$ 1.29	$ 0.24
Diluted	$ 0.39	$ 1.26	$ 0.22
Weighted-average shares outstanding:			
Basic	42,168	37,956	35,547
Diluted	42,666	38,871	38,697
Dividends per share:			
Common	$ 0.807	$ 0.563	$ 0.327
Preferred	—	—	$ 0.327

See accompanying notes to consolidated financial statements.

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CROSSTEX ENERGY, INC.

Consolidated Statements of Changes in Stockholders' Equity

	Preferred Stock Shares	Preferred Stock Amt	Common Stock Shares	Common Stock Amt	Additional Paid-In Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income	Notes Receivable	Total Stockholders' Equity
					(In thousands, except share data)					
Balance, December 31, 2003	4,123,642	$ 42	1,743,032	$ 19	$ 68,934	$ (2,500)	$ 7,549	$ 506	$ (5,284)	$ 69,266
Conversion of preferred to common	(4,123,642)	(42)	8,247,284	82	(40)	—	—	—	—	—
Two-for-one common stock split			1,743,032	16	(16)	—	—	—	—	—
Cancellation of treasury stock					(2,500)	2,500	—	—	—	—
Issuance of common units in public offering, net of offering costs of $1,512	—	—	345,900	3	4,794	—	—	—	—	4,797
Proceeds from exercise of stock options	—	—	177,642	2	947	—	—		—	949
Repayment of notes receivable	—	—	—	—	—	—	—	—	5,284	5,284
Stock-based compensation	—	—	—	—	474	—	—	—	—	474
Preferred dividends	—	—	—	—	—	—	(132)	—	—	(132)
Common dividends	—	—	—	—	—	—	(11,903)	—	—	(11,903)
Net income	—	—	—	—	—	—	8,700	—	—	8,700
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	(1,469)	—	(1,469)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	967	—	967
Balance, December 31, 2004	—	—	12,256,890	122	72,593	—	4,214	4	—	$ 76,933
Proceeds from exercise of stock options	—	—	681,039	7	3,803	—	—	—	—	3,810
Shares repurchased and cancelled	—	—	(177,771)	(2)	(8,232)	—	—	—	—	(8,234)
Capital contribution related to deferred tax benefits	—	—	—	—	10,185	—	—	—	—	10,185
Stock-based compensation	—	—	—	—	1,838	—	—	—	—	1,838
Common dividends	—	—	—	—	—	—	(21,603)	—	—	(21,603)
Net income	—	—	—	—	—	—	49,136	—	—	49,136
Non-controlling partners' share of other comprehensive income in Partnership	—	—	—	—	—	—	—	552	—	552
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	2,748	—	2,748
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	(4,118)	—	(4,118)
Balance, December 31, 2005	—	—	12,760,158	127	80,187	—	31,747	(814)	—	111,247
Three-for-one common stock split	—	—	30,627,458	309	(309)	—	—	—	—	—
Issuance of common stock, net of offering costs of $282	—	—	2,550,260	26	179,694	—	—	—	—	179,720
Proceeds from exercise of stock options	—	—	3,311	1	125	—	—	—	—	126
Stock-based compensation	—	—	—	—	3,567	—	—	—	—	3,567
Common dividends	—	—	—	—	—	—	(34,667)	—	—	(34,667)
Net income	—	—	—	—	—	—	16,455	—	—	16,455
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	(1,361)	—	(1,361)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	4,326	—	4,326
Balance, December 31, 2006	—	—	45,941,187	$ 463	$ 263,264	—	$ 13,535	$ 2,151	—	$ 279,413

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Comprehensive Income

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Net income	$ 16,455	$ 49,136	$ 8,700
Non-controlling partners’ share of other comprehensive income in the Partnership, net of taxes of $0, $315 and $0, respectively	—	552	—
Hedging gains or losses reclassified to earnings, net of taxes of $(779), $1,572 and $(826), respectively	(1,361)	2,748	(1,469)
Adjustment in fair value of derivatives, net of taxes of $2,460, $2,352 and $544, respectively	4,326	(4,118)	967
Comprehensive income	$ 19,420	$ 48,318	$ 8,198

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 16,455	$ 49,136	$ 8,700
Adjustments to reconcile net income to net cash provided by (used in) operating activities:			
Depreciation and amortization	82,792	36,070	23,034
Impairments	—	—	981
Gain on sale of property	(2,108)	(8,138)	(12)
Cumulative effect of change in accounting principle	(170)	—	—
Gain on issuance of units of the Partnership	(18,955)	(65,070)	—
Interest of non-controlling partners in the Partnership net income	(13,027)	4,652	8,239
Deferred tax expense	11,386	30,047	4,802
Non-cash stock based compensation	8,579	3,672	982
Amortization of debt issue costs	2,694	1,127	1,015
Loss on investment in affiliated partnerships	—	—	(304)
Non-cash derivatives loss	550	10,208	(279)
Changes in assets and liabilities net of acquisition effects:			
Accounts receivable and accrued revenue	77,324	(166,300)	(48,140)
Natural gas storage, prepaid expenses and other	12,999	(1,570)	(2,817)
Accounts payable, accrued gas purchased, and other accrued liabilities	(65,694)	132,975	50,684
Fair value of derivatives	—	(13,967)	(473)
Other	1,014	—	(73)
Net cash provided by operating activities	113,839	12,842	46,339
Cash flows from investing activities:			
Additions to property and equipment	(314,766)	(120,539)	(45,984)
Acquisitions and asset purchases	(576,110)	(505,518)	(78,895)
Proceeds from sale of property	5,051	10,991	611
(Increase) decrease to other non-current assets	—	244	(115)
Distributions from (contributions to) affiliated partnerships	—	—	12
Net cash used in investing activities	(885,825)	(614,822)	(124,371)
Cash flows from financing activities:			
Proceeds from borrowings	1,708,500	1,798,250	491,500
Payments on borrowings	(1,244,021)	(1,424,300)	(403,550)
Increase (decrease) in drafts payable	18,094	(8,812)	28,221
Distributions to non-controlling partners in the Partnership	(34,902)	(15,213)	(12,143)
Preferred dividends paid	—	—	(3,603)
Common dividends paid	(34,667)	(21,603)	(11,903)
Debt refinancing and offering costs	(5,646)	(6,919)	(1,370)
Net proceeds from issuance of units of the Partnership	179,185	273,255	—
Contributions from minority interest party	—	786	—
Treasury stock purchased	—	—	—
Common stock repurchased and cancelled	—	(8,234)	—
Proceeds from exercise of common stock options	126	3,810	949
Proceeds from exercise of Partnership unit options	3,328	1,345	425
Repayment of shareholder notes	—	—	5,284
Net proceeds from sale of common and preferred stock	179,720	—	5,262
Net cash provided by financing activities	769,717	592,365	99,072
Net increase (decrease) in cash and cash equivalents	(2,269)	(9,615)	21,040
Cash and cash equivalents, beginning of period	12,904	22,519	1,479
Cash and cash equivalents, end of period	$ 10,635	$ 12,904	$ 22,519
Cash paid for interest	$ 46,794	$ 14,598	$ 7,556
Cash paid for income taxes	$ (847)	$ 496	$ 549

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements
December 31, 2006 and 2005

1. Organization and Summary of Significant Agreements:

(a) Description of Business

Crosstex Energy, Inc. (the Company and formerly Crosstex Energy Holdings Inc.), a Delaware corporation formed on April 28, 2000, is engaged, through its subsidiaries, in the gathering, transmission, treating, processing and marketing of natural gas and NGLs. The Company connects the wells of natural gas producers in the geographic areas of its gathering systems in order to purchase the gas production, treats natural gas to remove impurities to ensure that it meets pipeline quality specifications, processes natural gas for the removal of natural gas liquids or NGLs, transports natural gas and ultimately provides an aggregated supply of natural gas to a variety of markets. In addition, the Company purchases natural gas from producers not connected to its gathering systems for resale and sells natural gas on behalf of producers for a fee.

(b) Organization, Public Offering of Units in CELP and Public Offering of the Company

On July 12, 2002, the Company formed Crosstex Energy, L.P. (herein referred to as the Partnership or CELP), a Delaware limited partnership. Crosstex Energy GP, L.P., a wholly owned subsidiary of the Company, is the general partner of the Partnership. The Company also owned 7,001,000 subordinated units, 6,414,830 senior subordinated series C units, and 2,999,000 common units in the Partnership through its wholly-owned subsidiaries on December 31, 2006 which represented 42.0% of the limited partner interests in the Partnership. In February 2007, 2,333,000 of the Partnership's subordinated units held by the Company converted to common units so the Company's ownership of subordinated units is 4,668,000 and common units is 5,332,000 upon this conversion.

In January 2004, the Company completed an initial public offering of its common stock. In conjunction with the public offering, the Company converted all of its preferred stock to common stock, cancelled its treasury stock and made a two-for-one stock split, effected in the form of a stock dividend. The Company's existing shareholders sold 6,918,000 common shares and the Company issued 1,037,700 common shares at a public offering price of $6.50 per common share. The Company received net proceeds of approximately $4.8 million from the common stock issuance. The Company's existing stockholders also repaid approximately $4.9 million in stockholder notes receivable in connection with the public offering. As of December 31, 2006, Yorktown owns 5.0% of the Company's outstanding common shares, Company management and directors own 14.2% of its common shares and the remaining 64.1% is held publicly. Common shares and public offering price are revised to reflect the two-for-one stock split in January 2004 and the three-for-one stock split in December 2006.

(c) Basis of Presentation

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

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

2. Significant Accounting Policies

(a) Management's Use of Estimates

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

(b) Cash and Cash Equivalents

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

(c) Natural Gas and Natural Gas Liquids Inventory

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

(d) Property, Plant, and Equipment

Property, plant and equipment consists of intrastate gas transmission systems, gas gathering systems, industrial supply pipelines, natural gas liquids pipelines, natural gas processing plants, natural gas liquids (NGLs) fractionation plants, an undivided 12.4% interest in a carbon dioxide processing plant, and gas treating plants.

Other property and equipment is primarily comprised of computer software and equipment, furniture, fixtures, leasehold improvements and office equipment. Such items are depreciated over their estimated useful life of three to seven years. Property, plant and equipment are recorded at cost. Repairs and maintenance are charged against income when incurred. Renewals and betterments, which extend the useful life of the properties, are capitalized. Interest costs are capitalized to property, plant and equipment during the period the assets are undergoing preparation for intended use. Interests costs totaling $5.4 million and $0.9 million were capitalized for the years ended December 31, 2006 and 2005, respectively. No interest costs were capitalized in 2004.

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

	Useful Lives
Transmission assets	15-25 years
Gathering systems	7-15 years
Gas treating, gas processing and carbon dioxide plants	15 years
Other property and equipment	3-7 years

Depreciation expense of $68.9 million, $31.7 million and $21.8 million was recorded for the years ended December 31, 2006, 2005 and 2004, respectively.

Statement of Financial Accounting Standards No. 144 (SFAS No. 144), *Accounting for the Impairment or Disposal of Long-Lived Assets*, requires long-lived assets to be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. In order to determine whether an impairment has occurred, the Company compares the net book value of the asset to the undiscounted expected future net cash flows. If an impairment has occurred, the amount of such impairment is determined based on the expected future net cash flows discounted using a rate commensurate with the risk associated with the asset. An impairment of $1.0 million was recorded in the year ended December 31, 2004. The impairment recorded in 2004 related to a processing plant owned directly by the Company. This plant has been inactive since late 2002 when the operator of the wells behind the plant cancelled its drilling plan for the area. An impairment on the contracts associated with the plant was recorded in 2002 but the value of the plant was not impaired because the Company intended to restart or relocate the plant. Drilling activity had increased in the area near the plant and processing margins had improved during 2004 so management decided to more fully evaluate the cost of restarting this idle plant. During 2004 management determined that it would be more commercially feasible to put a new plant at the plant site than to invest the capital necessary to restart the plant. If the Company does not restart the plant, our engineers estimate that the plant would receive very little, if any, value upon the sale of the plant. Therefore, the Company impaired the full value of the plant during 2004 under SFAS No. 144.

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

(e) Goodwill and Intangibles

The Company has approximately $25.4 million and $7.6 million of goodwill at December 31, 2006 and 2005, respectively. 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 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 2006, the Company 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 El Paso acquisition as discussed in Note (4) included $254.0 million of such intangibles. The Chief acquisition, as discussed in Note (4), included $396.0 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 $13.9 million, $4.3 million and $1.2 million for the years ended December 31, 2006, 2005 and 2004, respectively. As of December 31, 2006, accumulated amortization of intangible assets was $31.7 million.

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

2007	$ 29,702
2008	37,513
2009	42,462
2010	45,758
2011	47,558
Thereafter	435,609
Total	$ 638,602

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

(f) Other Assets

Unamortized debt issuance costs totaling $11.4 million and $8.4 million as of December 31, 2006 and 2005, respectively, are included in other non-current assets. Debt issuance costs are amortized into interest expense over the term of the related debt. Debt issuance costs are amortized into interest expense using the effective-interest method over the term of the debt for the senior secured notes. Debt issuance costs are amortized using the straight-line method over the term of the debt for the bank credit facility because borrowings under the bank credit facility cannot be forecasted for an effective-interest computation. Other assets as of December 31, 2005 also included the noncurrent portion of the note receivable of $0.4 million from RLAC Gathering Group, L.P., the minority interest partner in the CDC joint venture discussed in Note 5.

(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 Company had an imbalance payable of $2.9 million and $30.5 million at December 31, 2006 and 2005, respectively, which approximates the fair value for these imbalances. The Company had an imbalance receivable of $5.2 million and $7.8 million at December 31, 2006 and 2005, 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 Company did not provide any asset retirement obligations as of December 31, 2006 or 2005 because it does not have sufficient information as set forth in FIN 47 to reasonably estimate such obligations and the Company has no current intention of discontinuing use of any significant assets.

(i) Revenue Recognition

The Company recognizes revenue for sales or services at the time the natural gas or NGLs are delivered or at the time the service is performed. The Company generally accrues one to two months of sales and the related gas purchases and reverses these accruals when the sales and purchases are actually invoiced and recorded in the subsequent months. Actual results could differ from the accrual estimates. See discussion of accounting for energy trading activities in note 2(k).

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

(j) Commodity Risk Management

The Company engages in price risk management activities in order to minimize the risk from market fluctuations in the price of natural gas, oil and NGLs. To qualify as a hedge, the price movements in the commodity derivatives must be highly correlated with the underlying hedged commodity. Gains and losses related to commodity derivatives which qualify as hedges are recognized in income when the underlying hedged physical transaction closes and are included in the consolidated statements of operations as a cost of gas purchased.

The Company recognizes all derivative and hedging instruments in the statements of financial position as either assets or liabilities and measures them at fair value in accordance with Statement of Financial Accounting Standards No. 133 (SFAS No. 133), *Accounting for Derivative Instruments and Hedging Activities.* If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in 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. To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying item being hedged. In addition, all hedging relationship s must be designated, documented and reassessed periodically.

Currently, some of the derivative financial instruments that qualify for hedge accounting are designated as cash flow hedges. The cash flow hedge instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the gain or loss on these derivative instruments is recorded in other comprehensive income in stockholders' equity and reclassified into earnings in the same period in which the hedged transaction closes. The asset or liability related to the derivative instruments is recorded on the balance sheet in fair value of derivative assets or liabilities. Any ineffective portion of the gain or loss is recognized in earnings immediately.

Certain derivative financial instruments that qualify for hedge accounting are not designated as cash flow hedges. These financial instruments and their physical quantities are marked to market, and recorded on the balance sheet in fair value of derivative assets or liabilities with related earnings impact recorded in the period the transactions are entered into.

(k) Energy Trading Activities

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

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

For each reporting period, the Company records the fair value of open energy trading contracts based on the difference between the quoted market price and the contract price. Accordingly, the change in fair value from the previous period, in addition to the net realized gains or losses on settled contracts, is reported as net gain or loss on derivatives in the statements of operations.

Margins earned on settled contracts from its commercial services activities included in profit on energy trading contracts in the consolidated statement of operations was $2.5 million, $1.6 million, and $2.2 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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

	Years Ended December 31,		
	2006	2005	2004
Volumes purchased and sold	50,563,000	66,065,000	76,576,000

(l) Comprehensive Income (Loss)

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

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

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

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

(n) Concentrations of Credit Risk

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of trade accounts receivable and derivative financial instruments. Management believes the risk is limited as the Company's customers represent a broad and diverse group of energy marketers and end users. In addition, the Company continually monitors and reviews credit exposure to its marketing counterparties and letters of credit or other appropriate security are obtained as considered necessary to limit the risk of loss. See Note 10 for further discussion. The Company records reserves for uncollectible accounts on a specific identification basis since there is not a large volume of late paying customers. The Company had a reserve for uncollectible receivables as of December 31, 2006, 2005 and 2004 of $0.6 million, $0.3 million and $0.1 million, respectively.

During 2006 and 2005, Dow Hydrocarbons accounted for 13.4% and Formosa Hydrocarbons accounted for 10.6%, respectively, of the consolidated revenue of the Company. During 2004, Kinder Morgan accounted for 10.2% of the consolidated revenue of the Company. As the Company continues to grow and expand, this relationship between individual customer sales and consolidated total sales is expected to continue to change. While these customers represent a significant percentage of revenues, the loss of either would not have a material adverse impact on the Company's results of operations.

(o) Environmental Costs

Environmental expenditures are expensed or capitalized as appropriate, depending on the nature of the expenditures and their future economic benefit. Expenditures that related to an existing condition caused by past operations that do not contribute to current or future revenue generation are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (or a discounted basis when the obligation can be settled at fixed and determinable amounts) when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. For the years ended December 31, 2006, 2005 and 2004, such expenditures were not significant.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

(p) Option Plans

Effective January 1, 2006, the Company adopted the provisions of SFAS No. 123R, "*Share-Based Payment"* (SFAS No. 123R) which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements. The Company 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 Company elected to use the modified-prospective transition method for adopting SFAS No. 123R. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under SFAS No. 123R. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with SFAS No. 123R. The Company 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, net of taxes and minority interest, of $0.2 million due to the reduction in previously recognized compensation costs associated with the estimation of forfeitures.

The Company and the Partnership each have similar unit or share-based payment plans for employees, which are described below. Amounts recognized in the consolidated financial statements with respect to these plans are as follows (in thousands):

	Years Ended December 31,		
	2006	2005	2004
Cost of share-based compensation charged to general and administrative expense	$ 7,448	$ 3,660	$ 830
Cost of share-based compensation charged to operating expense	1,131	398	198
Total amount charged to income before cumulative effect of accounting change	$ 8,579	$ 4,058	$ 1,028
Interest of non-controlling partners in share-based compensation	$ 2,857	$ 869	$ 340
Amount of related income tax benefit recognized in income	$ 2,121	$ 1,116	$ 241

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

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

Had compensation cost for the Company 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 years ended December 31, 2005 and 2004, the Company's net income (loss) would have been as follows (in thousands except per share amounts):

	Years Ended	
	2005	2004
Net income as reported	$ 49,136	$ 8,700
Add: Stock-based employee compensation expense included in reported net income, net of tax	2,027	376
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax	(2,252)	(477)
Pro forma net income (loss)	$ 48,911	$ 8,599
Net income per common share, as reported:		
Basic	$ 1.29	$ 0.24
Diluted	$ 1.26	$ 0.22
Pro forma net income per common share:		
Basic	$ 1.29	$ 0.24
Diluted	$ 1.27	$ 0.22

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.

(q) Sales of Securities by Subsidiaries

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

(r) Recent Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48 (FIN 48), "*Accounting for Uncertainty in Income Taxes*". FIN 48 is an interpretation of FASB Statement No. 109, "*Accounting for Income Taxes*" and must be adopted by the Partnership no later than January 1, 2007. FIN 48 prescribes a comprehensive model for recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions that the Company has taken or expects to take in its returns. The Company is evaluating the impact of adopting FIN 48 and does not anticipate a significant impact on its financial statements.

On September 13, 2006, the Securities Exchange Commission (SEC) issued Staff Accounting Bulleting 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. SAB 108 is not expected to have a material impact on the Company.

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

(a) *Issuance of Common Units, Senior Subordinated Units and Senior Subordinated Series B Units*

The Crosstex Energy, L.P. partnership agreement contains specific provisions for the allocation of net earnings and losses to the partners for purposes of maintaining the partner capital accounts. Net income is allocated to the general partner based on incentive distributions earned for the period plus 2% of remaining net income. In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to the Company's stock options and restricted stock awarded to employees and directors of the Partnership all to the general partner to make the related general partner contribution.

On June 24, 2005, the Partnership issued 1,495,410 senior subordinated units in a private equity offering for net proceeds of $51.1 million, including our $1.1 million general partner contribution. The senior subordinated units were issued at $33.44 per unit, which represents 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. As a result of this offering, upon the conversion of these units to common units in the first quarter of 2006, the Company recognized a gain of $19.0 million due to the Partnership issuing additional units at prices per unit greater than the Company's equivalent carrying value.

On November 1, 2005, the Partnership issued 2,850,165 senior subordinated series B units in a private placement for a purchase price of $36.84 per unit. It received net proceeds of approximately $107.1 million, including our $2.1 million general partner contribution and net of 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. The senior subordinated series B units were not entitled to distributions paid on November 14, 2005. The net proceeds were used to fund a portion of the El Paso acquisition. As a result of this offering, the Company recognized a gain of $37.5 million due to the Partnership issuing additional units at prices per unit greater than the Company's equivalent carrying value.

In November and December 2005, the Partnership issued 3,731,050 additional common units to the public at $33.25 per unit. The offering resulted in net proceeds to the Partnership of approximately $120.9 million including our $2.5 million general partner contribution and net of expenses associated with the offering. The net proceeds from this offering were used to fund a portion of the El Paso acquisition. As a result of this offering, the Company recognized a gain of $27.6 million due to the Partnership issuing additional units at prices per unit greater than the Company's equivalent carrying value.

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. The Company purchased 6,414,830 of the senior subordinated series C units for a total of $180.0 million. In addition, the Company 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 will automatically convert into common units representing limited partner interests of the Partnership on the first date on or after February 16, 2008 that conversion is permitted by its partnership agreement at a ratio of one common unit for each senior subordinated series C unit. The partnership agreement will permit the conversion of the senior subordinated series C units to common units once the subordination period ends or if the issuance is in connection with an acquisition that increases cash flow from operations per unit on a pro forma basis. If not able to convert on February 16, 2008, then the holders of such units will have the right to receive, after payment of the minimum quarterly distribution on the Partnership's common units but prior to any payment on the Partnership's subordinated units, distributions equal to 110% of the quarterly cash distribution amount payable on common units. The senior subordinated series C units are not entitled to distributions of available cash from the Partnership until February 16, 2008. The Company may recognize a gain associated with the senior subordinated series C units purchased by non-controlling partners when such units convert to common units based on the Company's carrying value upon conversion.

(b) Limitation of Issuance of Additional Common Units

During the subordination period, the Partnership may issue up to 2,633,000 additional common units or an equivalent number of securities ranking on parity with the common units without obtaining unitholder approval. The Partnership may also issue an unlimited number of common units during the subordination period for acquisitions, capital improvements or debt repayments that increase cash flow from operations per unit on a pro forma basis.

(c) Subordination Period

The subordination period will end once the Partnership meets the financial tests in the partnership agreement, but it generally cannot end before December 31, 2007 except as discussed in (d) below. When the subordination period ends, each remaining subordinated unit will convert into one common unit and the common units will no longer be entitled to arrearages.

(d) Early Conversion of Subordinated Units

If the Partnership meets the applicable financial tests in the partnership agreement for the three consecutive four-quarter periods ending on December 31, 2005 or December 31, 2006, up to 4,666,000 of the subordinated units may be converted into common units prior to December 31, 2007. The Partnership met the financial tests for three consecutive four-quarter periods ended December 31, 2005, so 2,333,000 subordinated units converted to common units upon the payment of the fourth quarter distribution on February 15, 2006. The Partnership also met the financial tests for the three consecutive four-quarter period ended December 31, 2006, so an additional 2,333,000 of the subordinated units converted to common units upon payment of the fourth quarter distribution on February 15, 2007.

(e) 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 ending 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 (6) for a description of the bank credit facility covenants.

Under the quarterly incentive distribution provisions, generally its general partner is entitled to 13% of amounts the Partnership distributes in excess of $0.25 per unit, 23% of the amounts the Partnership distributes in excess of $0.3125 per unit and 48% of amounts the Partnership distributes in excess of $0.375 per unit. Incentive distributions totaling $20.4 million, $10.7 million and $5.6 million were earned by the Company for the years ended December 31, 2006, 2005 and 2004, respectively. To the extent there is sufficient available cash, the holders of common units are entitled to receive the minimum quarterly distribution of $0.25 per unit, plus arrearages, prior to any distribution of available cash to the holders of subordinated units. Subordinated units will not accrue any arrearages with respect to distributions for any quarter. The Partnership paid annual per common unit distributions of $2.18, $1.93, and $1.70 for the years ended December 31, 2006, 2005 and 2004, respectively.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

(f) *Allocation of Partnership Income*

Net income is allocated to Crosstex Energy GP, L.P., a wholly-owned subsidiary of the Company, as the Partnership's general partner in an amount equal to its incentive distributions as described in Note 2(e) above. In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to the Company's stock options and restricted stock all to the general partner to match the related general partner contribution for such items. Therefore, beginning in the second quarter of 2005, the general partner's share of the Partnership's net income is reduced by stock-based compensation expense attributed to the Company's stock options and restricted stock awarded to officers and employees of the Partnership. The remaining net income after incentive distributions and Company-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units (excluding senior subordinated units), and the common units. The following table reflects the Company's general partner share of the Partnership's net income (in thousands):

	Year Ended December 31,		
	2006	2005	2004
Income allocation for incentive distributions	$ 20,422	$ 10,660	$ 5,550
Stock-based compensation attributable to CEI's stock options and restricted shares	(3,545)	(2,223)	—
2% general partner interest in net income (loss)	(421)	215	363
General Partner Share of Net Income	$ 16,456	$ 8,652	$ 5,913

The Company also owns limited partner common units, limited partner subordinated units and limited partner senior subordinated series C units in the Partnership. The Company's share of the Partnership's net income attributable to its limited partner common and subordinated units was a net loss of $7.4 million for the year ended December 31, 2006 and net income of $6.3 million and $9.8 million for years ended December 31, 2005 and 2004, respectively.

4. Significant Asset Purchases and Acquisitions

In April 2004, the Partnership acquired, through its wholly-owned subsidiary Crosstex Louisiana Energy, L.P., the LIG Pipeline Company and its subsidiaries (LIG Inc., Louisiana Intrastate Gas Company, L.L.C., LIG Chemical Company, LIG Liquids Company, L.L.C. and Tuscaloosa Pipeline Company) (collectively, referred to as LIG) from American Electric Power (AEP) in a negotiated transaction for $73.7 million. LIG consists of approximately 2,000 miles of gas gathering and transmission systems located in 32 parishes extending from northwest and north-central Louisiana through the center of the state to south and southeast Louisiana. The Partnership financed the acquisition through borrowings under its amended bank credit facility. The Partnership utilized the purchase method of accounting for this acquisition with an acquisition date of April 1, 2004.

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 borrowings under its bank credit facility for the remaining balance.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

The Partnership has utilized the purchase method of accounting for this acquisition with an acquisition date of November 1, 2005. The purchase price and our allocation thereof are as follows (in thousands):

Cash paid to El Paso Corporation (net of estimated working capital adjustment)	$ 477,851
Direct acquisition costs	3,125
Total Purchase Price	$ 480,976
Assets acquired:	
Current assets	$ 49,693
Property, plant & equipment	235,599
Intangible assets	253,775
Liabilities assumed:	
Current liabilities	(58,091)
Total Purchase Price	$ 480,976

Intangible assets relate to customer relationships and are being amortized over 15 years. In 2006, the purchase price for El Paso was increased by $3.1 million due to changes in assets and liabilities assumed with the purchase.

On June 29, 2006, the Partnership acquired certain natural gas gathering pipeline systems and related facilities in the Barnett Shale (the North Texas Gathering, NTG assets) from Chief Holdings LLC (Chief) for a purchase price of approximately $475.3 million (the Chief Acquisition). The NTG assets include five gathering systems, located in parts of Parker, Tarrant, Denton, Palo Pinto, Erath, Hood, Somervell, Hill and Johnson counties in Texas. The NTG assets also included a 125 million cubic feet per day carbon dioxide treating plant and compression facilities with 26,000 horsepower. The gas gathering systems consisted of approximately 250 miles of existing gathering pipelines, ranging from four inches to twelve inches in diameter. The Partnership plans to build up to an additional 400 miles of pipelines as production in the area is drilled and developed. The gathering systems had the capacity to deliver approximately 250,000 MMBtu/d at the date of acquisition.

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 market-based gathering fees over the term. In addition to the Devon agreement, approximately 60,000 additional net acres are dedicated to the Midstream Assets under agreements with other producers.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

The Partnership utilized the purchase method of accounting for the acquisition of the Midstream Assets with an acquisition date of June 29, 2006. The Partnership will recognize the gathering fee income received from Devon and other producers who deliver gas into the Midstream Assets as revenue at the time the natural gas is delivered. The purchase price and our preliminary 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. The preliminary purchase price allocation has not been finalized because the Partnership is still in the process of determining the allocation of costs between tangible and intangible assets and finalizing working capital settlements.

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 El Paso assets have been included in the consolidated statements of operations since November 1, 2005. Operating results for the Midstream Assets have been included in the consolidated statements of operations since June 29, 2006. The following unaudited pro forma results of operations assume that the El Paso and Midstream Asset acquisitions occurred on January 1, 2005 (in thousands, except per unit amounts):

	Pro Forma Years Ended December 31,	
	2006	2005
	(Unaudited)	
Revenue	$ 3,155,854	$ 3,320,474
Net income	$ 15,295	$ 45,205
Net income (loss) per limited partner unit		
Basic	$ 0.33	$ 1.19
Diluted	$ 0.33	$ 1.16
Weighted average common shares outstanding		
Basic	45,941	12,652
Diluted	46,439	19,957

There are substantial differences in the way Chief operated the Midstream Assets during pre-acquisition periods and the way the Partnership operates these assets post-acquisition. The historical operating results for the El Paso assets only reflected direct revenues and expenses for such assets and did not include any general and administrative expenses because such expenses were not separately allocated to the acquired companies. Although the unaudited pro forma results of operations include adjustments to reflect the significant effects of the acquisitions, these pro forma results do not purport to present the results of operations had the acquisitions actually been completed as of January 1, 2005.

5. 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 their initial capital contribution. The loan bears interest at an annual rate of prime plus 2%. CDC makes payments directly to the Partnership attributable to CDC Partner's 50% share of distributable cash flow to repay the loan. Any balance remaining on the note is due in August 2007. The balance remaining on the note of $0.9 million is included in current notes receivable as of December 31, 2006.

Until December 31, 2004, the Partnership owned a 7.86% weighted average interest as the general partner in the five gathering systems of Crosstex Pipeline Partners, L.P., or CPP, and a 20.31% interest as a limited partner in CPP. The Company accounted for its investment in CPP under the equity method for the year ended December 31, 2004 because it exercised significant influence in operating decisions as a general partner in CPP.

Effective December 31, 2004, the Partnership acquired all of the outside limited and general partner interests of CPP for $5.1 million. This acquisition makes the Partnership the sole limited partner and general partner of CPP, so the Partnership began consolidating its investment in CPP effective December 31, 2004.

6. Long-Term Debt

As of December 31, 2006 and 2005, long-term debt consisted of the following (in thousands):

	2006	2005
Bank credit facility, interest based on Prime or LIBOR plus an applicable margin, interest rates at December 31, 2006 and 2005 were 7.20% and 6.69%, respectively	$ 488,000	$ 322,000
Senior secured notes, weighted average interest rates at December 31, 2006 and 2005 of 6.76% and 6.64%, respectively	498,530	200,000
Note payable to Florida Gas Transmission Company	600	650
	987,130	522,650
Less current portion	(10,012)	(6,521)
Debt classified as long-term	$ 977,118	$ 516,129

Credit Facility. On June 29, 2006, the Partnership amended its bank credit facility, increasing availability under the facility to $1.0 billion and extending the maturity date from November 2010 to June 2011. The bank credit agreement includes procedures for additional financial institutions selected by the Partnership to become lenders under the agreement, or for any existing lender to increase its commitment in an amount approved by the Partnership and the lender, subject to a maximum of $300 million for all such increases in commitments of new or existing lenders.

The facility was used for the 2005 El Paso acquisition and the 2006 Chief, Hanover and Cardinal acquisitions and will be used to finance the acquisition and development of gas gathering, treating, and processing facilities, as well as working capital, letters of credit, distributions and other general partnership purposes. At December 31, 2006, $564.3 million was outstanding under the facility, including $76.3 million of letters of credit, leaving approximately $435.7 million available for future borrowings. The facility will mature in June 2011, at which time it will terminate and all outstanding amounts shall be due and payable. Amounts borrowed and repaid under the credit facility may be re-borrowed.

Obligations under the 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 ranks *pari passu* in right of payment with the senior secured notes. The credit agreement is guaranteed by certain of its 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 the Partnership's 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.

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

- an initial ratio of total funded debt to consolidated earnings before interest, taxes, depreciation and amortization (each as defined in the credit agreement), measured quarterly on a rolling four-quarter basis, of 5.25 to 1.00, pro forma for any asset acquisitions. The maximum leverage ratio is reduced to 4.75 to 1.00 beginning July 1, 2007 and further reduces to 4.25 to 1.00 on January 1, 2008. The maximum ratio is increased to 5.25 to 1.00 during an acquisition period, as defined in the credit agreement; and
- 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 its 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.

In November 2006, the Partnership entered into an interest rate swap covering a principal amount of $50.0 million under the credit facility for a period of three years. The Partnership is subject to interest rate risk on its credit facility. The interest rate swap reduces this risk by fixing the LIBOR rate, prior to credit margin, at 4.95%, on $50.0 million of related debt outstanding over the term of the swap agreement which expires on November 30, 2009. The Partnership has elected not to designate this swap as a cash flow hedge for FAS 133 accounting treatment. Accordingly, unrealized gains or losses relating to the swap flow through the Consolidated Statement of Operations as adjustments to interest expense over the period hedged. The fair value of the interest rate swap at December 31, 2006 was a $0.1 million asset.

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 to $510.0 million, 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	(6,470)			
Balance as of December 31, 2006	$ 498,530			

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 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 in 2004, 2005 and 2006 provide for a call premium of 103.5% of par beginning three years after issuance at rates declining from 103.5% to 100.0%. The notes are not callable prior to three years after issuance. During 2007 the notes may also incur an additional fee ranging from 0.08% to 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.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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, 2006 and 2005 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 that is payable in $0.1 million annual increments through June 2006 with a final payment of $0.6 million due in June 2007. The note bears interest payable annually at LIBOR plus 1%.

Maturities: Maturities for the long-term debt as of December 31, 2006 are as follows (in thousands):

2007	$ 10,012
2008	9,412
2009	9,412
2010	20,294
2011	520,000
Thereafter	418,000

7. Income Taxes

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

	2006	2005	2004
Current tax provision	$ (268)	$ 0	$ 347
Deferred tax provision	11,386	30,047	4,802
	$ 11,118	$ 30,047	$ 5,149

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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

	2006	2005	2004
Federal income tax at statutory rate (35%)	$ 9,591	$ 27,714	$ 4,848
State income taxes, net	567	1,639	193
Tax basis adjustment in Partnership related to issuance of common units	1,151	993	—
Non-deductible expenses	88	9	91
Other	(279)	(308)	17
Tax provision	$ 11,118	$ 30,047	$ 5,149

The principal components of the Company's net deferred tax liability are as follows (in thousands):

	2006	2005
Deferred income tax assets:		
Net operating loss carryforward — current	$ 718	$ 5,902
Net operating loss carryforward — non-current	23,788	7,997
Enron reserve	—	156
Investment in the Partnership	6,983	5,832
Other comprehensive income	—	462
Other	100	41
	31,589	20,390
Less: valuation allowance	(6,983)	(5,832)
	24,606	14,558
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets — current	(501)	(496)
Property, plant, equipment, and intangible assets — non-current	(88,778)	(66,762)
Other comprehensive income	(1,231)	—
Other	(65)	(30)
	(90,575)	(67,288)
Net deferred tax liability	$ (65,969)	$ (52,730)

At December 31, 2006, the Company had a net operating loss carryforward of approximately $64.4 million that expires from 2021 through 2026. The Company also has various state net operating loss carryforwards of approximately $24.1 million which will begin expiring in 2019. Management believes that it is more likely than not that the future results of operations will generate sufficient taxable income to utilize these net operating loss carryforwards before they expire. Although the Company has generated net operating losses in the past and the Company expects to have significant amounts of future taxable income from its investment in the Partnership, particularly because of the remedial allocations of income among the unitholders and the allocation of income based on the Company's incentive distribution rights.

The Company generated federal income tax deductions of $3.5 million and $26.9 million during 2004 and 2005, respectively, attributable to the exercise of the Company's stock options which contributed to its net operating loss carryforward. The Company reduced its deferred tax liability and recognized a capital contribution of $10.2 million related to the tax benefits attributable to the stock option deductions.

Deferred tax liabilities relating to property, plant, equipment and intangible assets represent, primarily, the Company's share of the book basis in excess of tax basis for assets inside of the Partnership. The Company has also recorded a deferred tax asset in the amount of $7.0 million relating to the difference between its book and tax basis of its investment in the Partnership. Because the Company can only realize this deferred tax asset upon the liquidation of the Partnership and to the extent of capital gains, the Company has provided a full valuation allowance against this deferred tax asset. The valuation allowance increased $1.2 million from 2005 to 2006 due to the issuance of Partnership common units.

Effective January 1, 2007, the Company will be subject to the gross margin tax enacted by the state of Texas on May 1, 2006. The new tax law had so significant impact on the Company's net deferred tax liability.

8. Retirement Plans

The Company sponsors a single employer 401(k) plan for employees who become eligible upon the date of hire. The Partnership makes contributions at each compensation calculation period based on the annual discretionary contribution rate. Contributions to the plan for the years ended December 31, 2006, 2005 and 2004 were $1.1 million, $0.6 million and $0.5 million, respectively.

9. Employee Incentive Plans

(a) Long-Term Incentive Plan

In December 2002, the Partnership adopted a long-term incentive plan for its employees, directors, and affiliates who perform services for the Partnership. The plan currently permits the grant of awards covering an aggregate of 2,600,000 common unit options and restricted units. The plan is administered by the compensation committee of the Partnership's board of directors.

(b) Partnership Restricted Units

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

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the restricted units granted in 2005 and 2006 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, 2006 is provided below:

Crosstex Energy, L.P. Restricted Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	247,648	$ 28.33
Granted	130,008	35.01
Vested	(19,500)	12.99
Forfeited	(21,652)	25.69
Non-vested, end of period	336,504	$ 31.97
Aggregate intrinsic value, end of period (in thousands)	$ 13,410	

Restricted units totaling 163,934 were granted in 2005 with a weighted average grant-date fair value of $36.66 per unit. No restricted units were granted in 2004.

The aggregate intrinsic value of vested units during the year ended December 31, 2006 was $0.7 million. As of December 31, 2006, there was $5.8 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 1.8 years. The Partnership recognized stock-based compensation expense of $1.2 million and $0.3 million related to the amortization of restricted units in 2005 and 2004, respectively, in accordance with APB No. 25.

(c) Partnership Unit Options

Unit options will have an exercise price that is not less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the compensation committee. In addition, unit options will become exercisable upon a change in control of the Partnership, its general partner or its general partner's general partner.

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior. 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 2004 and 2005 were granted during the second quarter of each fiscal 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 2004 and 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 prior to 2005 generally vest based on five years of service (25% in years 3 and 4 and 50% in year 5) and the unit options granted in 2005 and 2006

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Notes to Consolidated Financial Statements — (Continued)

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 2006, 2005 and 2004:

Crosstex Energy, L.P. Unit Options Granted:	Years Ended December 31, 2006	2005	2004
Weighted average distribution yield	5.5%	5.5%	6.4%
Weighted average expected volatility	33.0%	33.0%	29.0%
Weighted average risk free interest rate	4.80%	3.83%	3.25%
Weighted average expected life	6 years	5.0 years	4.9 years
Weighted average contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$ 7.45	$ 8.42	$ 4.00

A summary of the unit option activity for the years ended December 31, 2006, 2005 and 2004 is provided below:

	Years Ended December 31, 2006 Number of Units	2006 Weighted Average Exercise Price	2005 Number of Units	2005 Weighted Average Exercise Price	2004 Number of Units	2004 Weighted Average Exercise Price
Outstanding, beginning of period	1,039,832	$ 18.88	1,043,865	$ 15.58	643,272	$ 10.28
Granted	286,403	34.62	193,511	32.78	466,296	22.52
Exercised	(304,936)	11.19	(127,097)	10.57	(39,066)	11.00
Forfeited	(95,143)	24.56	(70,447)	23.15	(26,637)	15.64
Outstanding, end of period	926,156	$ 25.70	1,039,832	$ 18.88	1,043,865	$ 15.58
Options exercisable at end of period	121,131	$ 23.58	308,455	$ 11.34	263,078	$ 10.36
Weighted average contractual term (years) end of period:						
Options outstanding	7.8	—	—	—	—	—
Options exercisable	7.5	—	—	—	—	—
Aggregate intrinsic value end of period (in thousands):						
Options outstanding	$ 13,107	—	—	—	—	—
Options exercisable	$ 1,970	—	—	—	—	—
Weighted average fair value of options granted with an exercise price equal to market price at grant	(a)	(a)	—	—	116,902	$ 4.91
Weighted average fair value of options granted with an exercise price less than market price at grant	(a)	(a)	193,511	$ 8.42	349,394	$ 3.70

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

The total intrinsic value of unit options exercised during the years ended December 31, 2006, 2005 and 2004 was $7.6 million, $3.5 million and $0.5 million, respectively. As of December 31, 2006, there was $2.6 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 1.8 years.

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

The Company has one stock-based compensation plan, the Crosstex Energy, Inc. Long-Term Incentive Plan. Prior to September 6, 2006, the plan permitted the grant of awards covering an aggregate of 1,200,000 options for common stock and restricted shares. On September 6, 2006, the Company's board of directors adopted, subject to stockholder approval, an Amended and Restated Long-Term Incentive Plan that increased the number of shares of common stock authorized for issuance under the plan to 1,530,000 shares. The Company's stockholders approved the plan on October 26, 2006. The plan is administered by the compensation committee of the Company's board of directors. The shares issued upon exercise or vesting are newly issued common shares.

The Company's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. The Company's restricted stock granted prior to 2005 generally vests based on five years of service (25% in years 3 and 4 and 50% in year 5) and restricted stock granted in 2005 and 2006 generally cliff vest after three years of service. A summary of the restricted stock activity for the year ended December 31, 2006 is provided below:

Crosstex Energy, Inc. Restricted Shares:	Number of Shares(a)	Weighted Average Grant-Date Fair Value(a)
Non-vested, beginning of period	589,641	$ 14.46
Granted	186,840	25.05
Vested	—	—
Forfeited	(24,732)	16.39
Non-vested, end of period	751,749	$ 17.03
Aggregate intrinsic value, end of period (in thousands)	$ 23,823	

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

Restricted shares totaling 404,640 were issued in 2005 with a weighted-average grant-date fair value of $16.73 per share. No restricted shares were granted in 2004.

The following assumptions were used for the Black-Scholes option-pricing model for the grants in 2005 and 2004:

	2005	2004
Weighted average distribution yield	3.2%	5.4%
Weighted average expected volatility	36.0%	30.0%
Weighted average risk free interest rate	3.67%	3.26%
Weighted average expected life	4.7 years	4.5 years
Weighted average contractual life	10 years	10 years
Weighted average of fair value of unit options granted (post stock split)	$ 3.68	$ 1.59

No stock options were granted to any directors, officers or employees during 2006.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

A summary of the stock option activity for the years ended December 31, 2006, 2005 and 2004, is provided below:

	Years Ended December 31,					
	2006		2005		2004	
	Number of Shares	Weighted Average Exercise Price	Number of Shares(a)	Weighted Average Exercise Price(a)	Number of Shares(a)	Weighted Average Exercise Price(a)
Outstanding, beginning of period	159,933	$ 9.53	2,161,152	$ 2.22	2,587,170	$ 1.81
Granted	—	—	68,958	13.85	130,908	8.48
Cancelled	—	—	(27,060)	15.23	(24,000)	1.71
Exercised	(9,933)	12.58	(2,043,117)	1.87	(532,926)	1.78
Forfeited	(30,000)	13.83	—	—	—	—
Outstanding, end of period	120,000	$ 8.21	159,933	$ 9.53	2,161,152	$ 2.22
Options exercisable at end of period	—	—	9,933	$ 12.58	1,986,249	$ 1.85
Weighted average fair value of options granted with an exercise price equal to market price at grant(a)	(b)	(b)	68,958	$ 3.68	120,000	$ 1.50
Weighted average fair value of options granted with an exercise price less than market at grant(a)	(b)	(b)	—	—	10,908	$ 2.53

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

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

The total intrinsic value of stock options exercised by directors, officers and employees during the years ended December 31, 2006, 2005 and 2004 was \$0.1 million, \$27.0 million and \$6.2 million, respectively.

As of December 31, 2006, there was \$6.9 million of unrecognized compensation costs related to non-vested CEI restricted stock and CEI's stock options. The cost is expected to be recognized over a weighted average period of 1.8 years.

(e) Earnings per share and anti-dilutive computations

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

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

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

The following are the share amounts used to compute the basic and diluted earnings per share for the years ended December 31, 2006, 2005 and 2004 (in thousands, except per-share amounts):

	Years Ended December 31, 2006	2005	2004
Basic earnings per share:			
Weighted average common shares outstanding	42,168	37,956	35,547
Dilutive earnings per share:			
Weighted average common shares outstanding	42,168	37,956	35,547
Dilutive effect of restricted shares	410	432	219
Dilutive effect of exercise of options	88	483	2,118
Dilutive effect of exercise of preferred stock conversion to common shares	—	—	813
Dilutive units	42,666	38,871	38,697

10. Fair Value of Financial Instruments

The estimated fair value of the Company's financial instruments has been determined by the Company using available market information and valuation methodologies. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided below are not necessarily indicative of the amount the Company could realize upon the sale or refinancing of such financial instruments (in thousands).

	December 31, 2006		December 31, 2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 10,635	$ 10,635	$ 12,904	$ 12,904
Trade accounts receivable and accrued revenues	367,023	367,023	428,927	428,927
Fair value of derivative assets	26,860	26,860	19,838	19,838
Account receivable from Enron	—	—	1,068	1,068
Note receivable	926	926	1,276	1,276
Accounts payable, drafts payable and accrued gas purchases	404,863	404,863	406,887	406,887
Current portion, long-term debt	10,012	10,012	6,521	6,521
Long-term debt	977,118	981,914	516,129	520,005
Fair value of derivative liabilities	14,699	14,699	18,359	18,359

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these assets and liabilities. The 2005 carrying amount of the account receivable from Enron approximates the fair value based on the estimated recoverable value for our claim in their bankruptcy proceedings as discussed in Note 11. 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 $488.0 million and $322.0 million as of December 31, 2006 and 2005, 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, 2006, the Partnership also had borrowings totaling $498.5 million under senior secured notes with a weighted average interest rate of 6.76%. The fair value of these borrowings as of December 31, 2006 and 2005 were adjusted to reflect to current market interest rate for such borrowings as of December 31, 2006 and 2005, 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

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” and “basis 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 the Partnership’s systems on one index and selling gas off that same system on a different index.

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. In December 2005 the Partnership sold a portion of those puts for $4.3 million. The Partnership did not designate these put options to obtain hedge accounting and therefore, these put options were marked to market through our consolidated statement of operations for the years ended December 31, 2005 and 2006. The puts represent options, but not obligations, to sell the related underlying liquids volumes at a fixed price.

The components of gain/loss on derivatives in the consolidated statements of operations are (in thousands):

	December 31, 2006	December 31, 2005	December 31, 2004
Change in fair value of derivates that do not qualify for hedge accounting	$ 713	$ 10,169	$ 769
Realized (gains) losses on derivatives	(2,238)	(240)	(1,031)
Ineffective portion of derivatives qualifying for hedge accounting	(74)	39	(17)
	$ (1,599)	$ 9,968	$ (279)

The fair value of derivative assets and liabilities, excluding the interest rate swap, are as follows (in thousands):

	December 31, 2006	December 31, 2005
Fair value of derivative assets — current	$ 22,959	$ 12,205
Fair value of derivative assets — long term	3,812	7,633
Fair value of derivative liabilities — current	(12,141)	(14,782)
Fair value of derivative liabilities — long term	(2,558)	(3,577)
Net fair value of derivatives	$ 12,072	$ 1,479

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

Set forth below is the summarized notional amount and terms of all instruments held for price risk management purposes at December 31, 2006 (all quantities are expressed in British Thermal Units and liquids are expressed in gallons). The remaining term of the contracts extend no later than March 2008 for derivatives, excluding third-party on-system financial swaps, and extend to June 2010 for third-party on-system financial swaps. The Partnership's counterparties to derivative contracts include BP Corporation, Total Gas & Power, Fortis, UBS Energy, Morgan Stanley and J. Aron & Co., a subsidiary of Goldman Sachs. Changes in the fair value of the Partnership's derivatives related to third-party producers and customers gas marketing activities 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 and the ineffective portion is recorded in earnings.

December 31, 2006

Transaction type	**Total Volume**	**Pricing Terms**	**Remaining Term of Contracts**	**Fair Value (In thousands)**
Cash Flow Hedges:				
Natural gas swaps	171,000	NYMEX less a basis of $0.785 to	January 2007 — June 2007	$ 73
Natural gas swaps	(3,117,000)	NYMEX less a basis of $0.575 or fixed prices ranging from $8.20 to $10.855 settling against various Inside FERC Index prices	January 2007 — March 2008	6,191
Total natural gas swaps designated as cash flow hedges				$ 6,264
Liquids swaps	(26,747,768)	Fixed prices ranging from $0.61 to $1.6275 settling against Mt. Belvieu Average of daily postings (non-TET)	January 2007 — March 2008	$ 1,766
Total liquids swaps designated as cash flow hedges				$ 1,766
Mark to Market Derivatives:				
Swing swaps	1,685,625	Prices ranging from Inside FERC Index less	January 2007	$ (2)
Swing swaps	(651,000)	$0.0275 to Inside FERC Index plus $0.01 or a fixed price of $5.93 settling against various Gas Daily Index prices	January 2007	(12)
Total swing swaps				$ (14)
Physical offset to swing swap transactions	651,000	Prices of various Inside FERC Index prices	January 2007	—
Physical offset to swing swap transactions	(1,685,625)	settling against various Gas Daily Index prices	January 2007	—
Total physical offset to swing swaps				$ —

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

December 31, 2006

Transaction type	Total Volume	Pricing Terms	Remaining Term of Contracts	Fair Value (In thousands)
Basis swaps				
Basis swaps	31,040,000	NYMEX less a basis of $0.785 to NYMEX plus a basis of $0.145 or prices ranging from $7.31 to $10.505 settling against various Inside FERC Index prices.	January 2007 — March 2008	$ (31)
	(31,414,000)		January 2007 — March 2008	(137)
Total basis swaps				$ (168)
Physical offset to basis swap transactions				
Physical offset to basis swap transactions	5,090,000	Prices ranging from Inside FERC Index less $0.09 to Inside FERC Index plus $0.0175 or a fixed price of $7.31 settling against various Inside FERC Index prices	January 2007 — March 2007	$ (30,417)
	(4,935,000)		January 2007 — March 2007	30,891
Total physical offset to basis swap transactions				$ 474
Third party on-system financial swaps	8,415,800	Fixed prices ranging from $5.659 to $11.91 settling against various Inside FERC Index prices	January 2007 — June 2010	$ (9,420)
Total third party on-system financial swaps				$ (9,420)
Physical offset to third party on-system transactions	(8,415,800)	Fixed prices ranging from $5.71 to $11.96 settling against various Inside FERC Index prices	January 2007 — June 2010	$ 10,176
Total physical offset to third party on-system swaps				$ 10,176
Storage swap transactions:				
Storage swap transactions	(355,000)	Fixed price of $10.065 settling against various Inside FERC Henry Hub Index price	February 2007	$ 1,333
Total financial storage swap transactions				$ 1,333
Natural gas liquid puts:				
Liquid put options (purchased)	80,497,830	Fixed prices ranging from $0.565 to $1.26 settling against Mount Belvieu Average Daily Index	January 2007 — December 2007	$ 3,117
Liquid put options (sold)	(37,713,696)		January 2007 — December 2007	(1,456)
Total natural gas liquid puts				$ 1,661

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, 2006, net gains on futures and basis swap hedge contracts increased gas revenue by $5.9 million. For the year ended December 31, 2005, net losses on futures and basis swap hedge contracts decreased gas revenue by $7.0 million. As of December 31, 2006, an unrealized pre-tax derivative fair value gain of $6.3 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income. Of this amount, $5.4 million is expected to be reclassified into earnings through December 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

The settlement of futures contracts and basis swap agreements related to January 2007 gas production increased gas revenue by approximately $0.7 million.

Liquids

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, 2005, net losses on liquids swap hedge contracts decreased liquids revenue by approximately $1.2 million. For the year ended December 31, 2006, an unrealized pre-tax derivative fair value gain of $1.8 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income. Of this amount, $1.5 million is expected to be reclassified into earnings through December 2007. 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.

Assets and liabilities related to third party derivative contracts, swing swaps, storage swaps and puts 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 on a net basis 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, 2006	$ 3,872	$ 49	$ 121	$ 4,042

Account Receivable from Enron

On December 2, 2001, Enron Corp. and certain subsidiaries, including Enron North America Corp. ("Enron"), each filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Bankruptcy Code. The Company had allowed unsecured claims in the Enron bankruptcy matter which total approximately $7.8 million. The Company wrote these claims down to $1.3 million at December 31, 2004. During the year ending December 31, 2005 and 2006, we received payments on the Enron receivable in the amount of $0.2 million and $2.7 million, respectively, and recognized other income of $1.6 million in 2006 for the amount collected in excess of the carrying value.

12. Transactions with Related Parties

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, a major shareholder in CEI. During the years ended December 31, 2006, 2005 and 2004, the Partnership purchased natural gas from Camden in the amount of approximately $32.5 million, $67.2 million, and $38.4 million, respectively, and received approximately $2.6 million, $2.6 million, and $2.4 million, respectively, in treating fees from Camden. During the year ended December 31, 2006, the Partnership received treating fees of $1.3 million and $0.3 million from Erskine and Approach, respectively.

During the year ended December 31, 2004, the Partnership was the general partner and a limited partner in CPP as discussed in Note 5. The Partnership had related-party transactions with CPP, as summarized below:

- During the year ended December 31, 2004, the Partnership bought natural gas from CPP in the amount of approximately $11.6 million and paid approximately $51,000 for transportation to CPP.
- During the year ended December 31, 2004, the Partnership received a management fee from CPP in the amount of approximately $125,000.
- During the year ended December 31, 2004, the Partnership received distributions from CPP in the amount of approximately $159,000.

Effective December 31, 2004, the Partnership acquired all of the outside limited and general partner interests of the CPP Partnership for $5.1 million. This acquisition makes the Partnership the sole limited partner and general partner of CPP, so the Partnership began consolidating its investment in CPP effective December 31, 2004.

13. Commitments and Contingencies

(a) Leases — Lessee

The Partnership has operating leases for office space, office and field equipment and the Eunice plant. The Eunice plant operating lease acquired in the El Paso acquisition provides for annual lease payments of $12.2 million with a lease term extending to April 15, 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 for leased office space and office and field equipment with initial or remaining non-cancelable lease terms in excess of one year (in millions):

2007	$ 18.7
2008	17.8
2009	17.1
2010	16.0
2011	16.0
Thereafter	17.6
	$ 103.2

Operating lease rental expense for the years ended December 31, 2006, 2005 and 2004 was approximately $23.8 million, $3.4 million and $2.8 million, respectively.

(b) Leases — Lessor

During 2006 the Company leased approximately 54 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 24 months at which time the leases revert to 30-day cancelable leases. As of December 31, 2006, the Company only had 29 treating plants under operating leases with remaining non-cancelable lease terms in excess of one year. The future minimum lease rentals are $10.6 million and $6.7 million for the years ended December 31, 2007 and 2008, respectively. These leased treating plants have a cost of $35.0 million and accumulated depreciation of $6.6 million as of December 31, 2006.

(c) Employment Agreements

Certain members of management of the Company are parties to employment contacts with the general partner. The employment agreements provide each member of senior management 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. The estimated remediation costs are expected to be approximately $0.5 million. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to the Partnership's ownership, these costs were accrued as part of the purchase price.

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

The Partnership acquired assets from DEFS in June 2003 that have environmental contamination, including a gas plant in Montgomery County near Conroe, Texas. At Conroe, contamination from historical operations has been identified at levels that exceed the applicable state action levels. Consequently, site investigation and/or remediation are underway to address those impacts. The remediation cost for the Conroe plant site is currently estimated to be approximately $3.2 million. Under the purchase agreement, DEFS has retained liability for cleanup of the Conroe site. Moreover, DEFS has entered into an agreement with a third-party company pursuant to which the remediation costs associated with the Conroe site have been assumed by this third-party company that specializes in remediation work.

(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.

14. Capital Stock

(a) Common Stock

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

In October 2006, the Company's stockholders approved an increase in the number of authorized shares of capital stock from 20 million shares, consisting of 19 million shares of common stock and 1 million shares of preferred stock, to 150 million shares, consisting of 140 million shares of common stock and 10 million shares of preferred stock. In January 2004, the Company made a two-for-one stock split in conjunction with its initial public offering discussed in Note 1(b).

(b) Sale of Capital Stock

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

(c) Notes Receivable

In January 2004, $4.9 million in stockholder notes receivable were repaid in conjunction with the Company's initial public offering discussed in Note 1(b) and the remaining notes receivable were repaid in December 2004.

15. Segment Information

Identification of operating segments is based principally upon differences in the types and distribution channel of products. The Company's reportable segments consist of Midstream and Treating. The Midstream division consists of the Company's natural gas gathering and transmission operations and includes the south Louisiana processing and liquids assets, the gathering and transmission assets located in north and south Texas, the LIG pipelines and processing plants located in Louisiana, the Mississippi System, the Arkoma System in Oklahoma and various other small systems. Also included in the Midstream division are the Company's energy trading operations. The operations in the Midstream segment are similar in the nature of the products and services, the nature of the production processes, the type of customer, the methods used for distribution of products and services and the nature of the regulatory environment. The Treating division generates fees from its plants either through volume-based treating contracts or though fixed monthly payments. The 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 Company evaluates the performance of its operating segments based on operating revenues and segment profits. Corporate expenses include, general corporate expenses associated with managing the operating segments. Corporate assets consist principally of property and equipment, including software, for general corporate support, working capital and debt refinancing costs. Intersegment sales are at cost.

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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

	Midstream	Treating	Corporate	Totals
		(In thousands)		
Year ended December 31, 2006:				
Sales to external customers	$ 3,073,069	$ 66,225	$ —	$ 3,139,294
Profit on energy trading activities	2,510	—	—	2,510
Purchased gas	(2,859,815)	(9,463)	—	(2,869,278)
Operating expenses	(80,988)	(20,048)	—	(101,036)
Segment profit	$ 134,776	$ 36,714	$ —	$ 171,490
Inter-segment sales	$ 10,520	$ (10,520)	$ —	$ —
Gain (loss) on derivatives	$ 1,591	$ 8	$ —	$ 1,599
Depreciation and amortization	$ (63,409)	$ (15,800)	$ (3,583)	$ (82,792)
Capital expenditures (excluding acquisitions)	$ 294,597	$ 31,463	$ 8,184	$ 334,244
Identifiable assets	$ 1,962,543	$ 203,528	$ 40,627	$ 2,206,698
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	(41,997)	(14,771)	—	(56,768)
Segment profit	$ 81,622	$ 24,129	$ —	$ 105,751
Inter-segment sales	$ 10,003	$ (10,003)	$ —	$ —
Gain (loss) on derivatives(a)	$ (9,968)	$ —	$ —	$ (9,968)
Depreciation and amortization	$ (23,289)	$ (10,646)	$ (2,135)	$ (36,070)
Capital expenditures (excluding acquisitions)	$ 98,284	$ 22,886	$ 6,512	$ 127,682
Identifiable assets	$ 1,281,576	$ 130,435	$ 33,314	$ 1,445,325
Year ended December 31, 2004:				
Sales to external customers	$ 1,948,021	$ 30,755	$ —	$ 1,978,776
Profit on energy trading activities	2,228	—	—	2,228
Purchased gas	(1,861,204)	(5,274)	—	(1,866,478)
Operating expenses	(29,540)	(8,856)	—	(38,396)
Segment profit	$ 59,505	$ 16,625	$ —	$ 76,130
Inter-segment sales	$ 6,360	$ (6,360)	$ —	$ —
Gain (loss) on derivatives	$ 279	$ —	$ —	$ 279
Impairments	$ (981)	$ —	$ —	$ (981)
Depreciation and amortization	$ (15,106)	$ (7,272)	$ (656)	$ (23,034)
Capital expenditures (excluding acquisitions)	$ 17,405	$ 25,141	$ 3,438	$ 45,984
Identifiable assets	$ 491,275	$ 90,287	$ 25,206	$ 606,768

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

CROSSTEX ENERGY, INC.

Notes to Consolidated Financial Statements — (Continued)

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

	Years Ended December 31, 2006	2005	2004
Segment profits	$ 171,490	$ 105,751	$ 76,130
General and administrative expenses	(47,707)	(34,145)	(20,005)
Impairments	—	—	(981)
Gain (loss) on derivatives	1,599	(9,968)	279
Gain on sale of property	2,108	8,138	12
Depreciation and amortization	(82,792)	(36,070)	(23,034)
Operating income	$ 44,698	$ 33,706	$ 30,401

16. Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per share amount)				
2006:					
Revenues	$ 817,119	$ 744,655	$ 855,285	$ 724,745	$ 3,141,804
Operating income	10,355	9,344	14,866	10,133	44,698
Net income	12,832	1,642	1,516	465	16,455
Basic earnings per common share	$ 0.34	$ 0.04	$ 0.03	$ 0.01	$ 0.39
Diluted earnings per common share	$ 0.33	$ 0.04	$ 0.03	$ 0.01	$ 0.39
2005:					
Revenues	$ 549,989	$ 630,805	$ 782,757	$ 1,069,497	$ 3,033,048
Operating income	6,477	7,087	3,614	16,528	33,706
Net income	1,572	1,746	755	45,063	49,136
Basic earnings per common share	$ 0.04	$ 0.05	$ 0.02	$ 1.18	$ 1.29
Diluted earnings per common share	$ 0.04	$ 0.05	$ 0.02	$ 1.16	$ 1.26

SCHEDULE I

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,812	$ 11,499
Deferred tax asset	—	5,190
Prepaid expenses and other	104	91
Total current assets	9,916	16,780
Investment in the Partnership	326,760	143,324
Investment in subsidiary	—	1,068
Total assets	$ 336,676	$ 161,172
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Payable to the Partnership	$ 23	$ 173
Other accrued liabilities	50	53
Total current liabilities	73	226
Deferred tax liability	57,190	49,699
Stockholders' equity:		
Common stock	463	127
Additional paid-in capital	263,264	80,187
Retained earnings	13,535	31,747
Accumulated other comprehensive income	2,151	(814)
Total stockholders' equity	279,413	111,247
Total liabilities and stockholders' equity	$ 336,676	$ 161,172

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

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2006	2005	2004
	(In thousands except share data)		
Operating income and expenses:			
Income from investment in the Partnership	$ 8,324	$ 14,943	$ 15,754
Income (Loss) from investment in subsidiary	1,000	(400)	(1,044)
General and administrative expense	(1,476)	(1,077)	(1,096)
Operating income	7,848	13,466	13,614
Other income (expense):			
Interest and other income	378	432	73
Income before gain on issuance of units by the Partnership and income taxes	8,226	13,898	13,687
Gain on issuance of units in the Partnership	18,955	65,070	—
Income tax provision expense	(10,896)	(29,832)	(4,987)
Net income before cumulative effect of change in accounting principle	16,285	49,136	8,700
Cumulative effect of change in accounting principle from investment in the Partnership	170	—	—
Net income	$ 16,455	$ 49,136	$ 8,700
Net income before cumulative effect of change in accounting principle per common share:			
Basic	$ 0.39	$ 1.29	$ 0.24
Diluted	$ 0.39	$ 1.26	$ 0.22
Cumulative effect of change in accounting principle per common share:			
Basic	—	—	—
Diluted	—	—	—
Net income per common share:			
Basic	$ 0.39	$ 1.29	$ 0.24
Diluted	$ 0.39	$ 1.26	$ 0.22
Weighted average common shares outstanding:			
Basic	42,168	37,956	35,547
Diluted	42,666	38,871	38,697

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

CROSSTEX ENERGY, INC. (PARENT COMPANY)

CONDENSED STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2006	2005	2004
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 16,455	$ 49,136	$ 8,700
Adjustments to reconcile net income (loss) to net cash flow provided by (used in) operating activities:			
Income from investment in the Partnership	(8,324)	(14,943)	(15,754)
(Income) loss from investment in subsidiary	(1,000)	400	1,044
Deferred taxes	10,896	29,832	4,992
Stock-based compensation	22	—	28
Gain on issuance of units in the Partnership	(18,955)	(65,070)	—
Cumulative effect of change in accounting principle from investment in the Partnership	(170)	—	—
Other	—	(38)	—
Changes in assets and liabilities:			
Accounts receivable	—	(57)	—
Prepaid expenses and other	(13)	139	(97)
Accounts payable and other accrued liabilities	(153)	(377)	(333)
Net cash provided by (used in) operating activities	(1,242)	(978)	(1,420)
Cash flows from investing activities:			
Investment in the Partnership	(189,407)	(6,317)	—
Distributions from the Partnership	41,711	28,093	21,184
Dividends from subsidiary	2,072	19	4,927
Net cash provided by (used in) investing activities	(145,624)	21,795	26,111
Cash flows from financing activities:			
Proceeds from sale of common and preferred stock	179,720	—	5,262
Proceeds from exercise of common stock options	126	3,810	949
Common stock repurchased and cancelled	—	(8,234)	—
Preferred dividends paid	—	—	(3,603)
Common dividends paid	(34,667)	(21,603)	(11,903)
Net cash provided by (used in) financing activities	145,179	(26,027)	(9,295)
Net increase (decrease) in cash	(1,687)	(5,210)	15,396
Cash, beginning of year	11,499	16,709	1,313
Cash, end of year	$ 9,812	$ 11,499	$ 16,709

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

SCHEDULE II

CROSSTEX ENERGY, INC.

VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
		(In thousands)			
Year Ended December 31, 2006:					
For doubtful receivables classified as non-current assets	$ 259	$ 359	—	—	$ 618
Year Ended December 31, 2005:					
For doubtful receivables classified as non-current assets	$ 59	200	—	—	$ 259
Year Ended December 31, 2004:					
For doubtful receivables classified as non-current assets	$ 6,931	—	—	$ (6,931)(a)	—

(a) The allowance for doubtful receivables for the Enron claims was written off against the receivable balance in 2004 pursuant to the Company's allowed claim in Enron's bankruptcy proceedings.

EXHIBIT INDEX

Number		Description
3.1	—	Amended and Restated Certificate of Incorporation of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006).
3.2	—	Third Amended and Restated Bylaws of Crosstex Energy, Inc. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated March 22, 2006, filed with the Commission on March 28, 2006).
3.3	—	Certificate of Limited Partnership of Crosstex Energy, L.P. (incorporated by reference from Exhibit 3.1 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.4	—	Fifth Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of June 29, 2006 (incorporated by reference to Exhibit 3.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
3.5	—	Certificate of Limited Partnership of Crosstex Energy Services, L.P. (incorporated by reference from Exhibit 3.3 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.6	—	Second Amended and Restated Agreement of Limited Partnership of Crosstex Energy Services, L.P., dated as of April 1, 2004 (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2004).
3.7	—	Certificate of Limited Partnership of Crosstex Energy GP, L.P. (incorporated by reference from Exhibit 3.5 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.8	—	Agreement of Limited Partnership of Crosstex Energy GP, L.P., dated as of July 12, 2002 (incorporated by reference from Exhibit 3.6 to Crosstex Energy L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.9	—	Certificate of Formation of Crosstex Energy GP, LLC (incorporated by reference from Exhibit 3.7 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-97779).
3.10	—	Amended and Restated Limited Liability Company Agreement of Crosstex Energy GP, LLC, dated as of December 17, 2002 (incorporated by reference from Exhibit 3.8 from Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
3.11	—	Amended and Restated Certificate of Formation of Crosstex Holdings GP, LLC (incorporated by reference from Exhibit 3.11 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.12	—	Limited Liability Company Agreement of Crosstex Holdings GP, LLC, dated as of October 27, 2003 (incorporated by reference from Exhibit 3.12 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.13	—	Certificate of Formation of Crosstex Holdings LP, LLC (incorporated by reference from Exhibit 3.13 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.14	—	Limited Liability Company Agreement of Crosstex Holdings LP, LLC, dated as of November 4, 2003 (incorporated by reference from Exhibit 3.14 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.15	—	Amended and Restated Certificate of Limited Partnership of Crosstex Holdings, L.P. (incorporated by reference from Exhibit 3.15 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
3.16	—	Agreement of Limited Partnership of Crosstex Holdings, L.P., dated as of November 4, 2003 (incorporated by reference from Exhibit 3.16 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
4.1	—	Specimen Certificate representing shares of common stock (incorporated by reference from Exhibit 4.1 to Crosstex Energy, Inc.'s Registration Statement on Form S-1, file No. 333-110095).
4.2	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy, Inc., Chieftain Capital Management, Inc., Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LB I Group Inc., Lubar Equity Fund, LLC and Tortoise North American Energy Corp. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).

Number		Description
10.1	—	Omnibus Agreement dated December 17, 2002, among Crosstex Energy, Inc. and certain other parties (incorporated by reference from Exhibit 10.5 to Crosstex Energy, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2002, file No. 000-50067).
10.2†	—	Form of Indemnity Agreement (incorporated by reference from Exhibit 10.2 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.3†	—	Crosstex Energy GP, LLC Long-Term Incentive Plan dated July 12, 2002 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, L.P.'s Annual Report on Form 10-K, file No. 000-50067).
10.4†	—	Amendment to Crosstex Energy GP, LLC Long-Term Incentive Plan, dated May 2, 2005 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated May 2, 2005, filed with the Commission on May 6, 2005).
10.5	—	Agreement Regarding 2003 Registration Rights Agreement and Termination of Stockholders' Agreement, dated October 27, 2003 (incorporated by reference from Exhibit 10.4 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.6†	—	Crosstex Energy, Inc. Amended and Restated Long-Term Incentive Plan effective as of September 6, 2006 (incorporated by reference to Exhibit 10.1 to Crosstex Energy, Inc.'s Current Report on Form 8-K dated October 26, 2006, filed with the Commission on October 31, 2006).
10.7	—	Registration Rights Agreement, dated December 31, 2003 (incorporated by reference from Exhibit 10.6 to Crosstex Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2003).
10.8	—	Fourth Amended and Restated Credit Agreement, dated November 1, 2005, among Crosstex Energy Services, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated November 1, 2005, filed with the Commission on November 3, 2005).
10.9	—	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 24, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.2 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated March 13, 2006, filed with the Commission on March 16, 2006).
10.10	—	Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 29, 2006, among Crosstex Energy, L.P., Bank of America, N.A. and certain other parties (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).
10.11	—	Amended and Restated Note Purchase Agreement, dated as of July 25, 2006, among Crosstex Energy, L.P. and the Purchasers listed on the Purchaser Schedule attached thereto (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated July 25, 2006, filed with the Commission on July 28, 2006).
10.12	—	Purchase and Sale Agreement, dated as of May 1, 2006, by and between Crosstex Energy Services, L.P., Chief Holdings LLC and the other parties named therein (incorporated by reference to Exhibit 10.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated May 1, 2006, filed with the Commission on May 4, 2006).
10.13	—	Seminole Gas Processing Plant Gaines County, Texas Joint Operating Agreement dated January 1, 1993 (incorporated by reference to Exhibit 10.10 to Crosstex Energy, L.P.'s Registration Statement on Form S-1, file No. 333-106927).
10.14	—	Stock Purchase Agreement, dated as of May 16, 2006, by and among Crosstex Energy, L.P. and each of the Purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated May 16, 2006, filed with the Commission on May 17, 2006).
10.15	—	Senior Subordinated Series C Unit Purchase Agreement, dated May 16, 2006 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 May 16, 2006, filed with the Commission on May 17, 2006).
10.16	—	Registration Rights Agreement, dated as of June 29, 2006, by and among Crosstex Energy, L.P., Chieftain Capital Management, Inc., Energy Income and Growth Fund, Fiduciary/Claymore MLP Opportunity Fund, Kayne Anderson MLP Investment Company, Kayne Anderson Energy Total Return Fund, Inc., LB I Group Inc., Tortoise Energy Infrastructure Corporation, Lubar Equity Fund, LLC and Crosstex Energy, Inc. (incorporated by reference to Exhibit 4.1 to Crosstex Energy, L.P.'s Current Report on Form 8-K dated June 29, 2006, filed with the Commission on July 6, 2006).

Number		Description
21.1*	—	List of Subsidiaries.
23.1*	—	Consent of KPMG LLP.
31.1*	—	Certification of the Principal Executive Officer.
31.2*	—	Certification of the Principal Financial Officer.
32.1*	—	Certification of the Principal Executive Officer and the Principal Financial Officer of the Company pursuant to 18 U.S.C. Section 1350.

* Filed herewith.

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

Exhibit 21.1

LIST OF SUBSIDIARIES

Name of Subsidiary	State of Organization
Crosstex Energy, L.P.	Delaware
Crosstex Energy GP, LLC	Delaware
Crosstex Energy GP, L.P.	Delaware
Crosstex Holdings, L.P.	Delaware
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 Processing Services, LLC	Delaware
Crosstex Pelican, LLC	Delaware
Crosstex NGL Marketing, L.P.	Texas
Sabine Pass Plant Facility, J.V.	Texas

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

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

We consent to the incorporation by reference in the registration statements No. 333-134713 and 333-136734 on Forms S-3 and Form S-8 of Crosstex Energy, Inc. and subsidiaries (No. 333-114014) of our reports dated February 28, 2007, with respect to the consolidated balance sheets of Crosstex Energy, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, changes in stockholders' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2006, and all related financial statement schedules, management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 and the effectiveness of internal control over financial reporting as of December 31, 2006, which reports appear in the December 31, 2006 annual report on Form 10-K of Crosstex Energy, Inc.

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

/s/ KPMG LLP

Dallas, Texas
February 28, 2007

Exhibit 31.1

CERTIFICATIONS

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

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

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

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

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

(a) Designed such disclosure controls and procedures, or caused 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 data 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 controls over financial reporting.

/s/ BARRY E. DAVIS

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

Date: February 28, 2007

Exhibit 31.2

CERTIFICATIONS

I, William W. Davis, Executive Vice President and Chief Financial Officer of Crosstex Energy, Inc., certify that:

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

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

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

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

(a) Designed such disclosure controls and procedures, or caused 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 data 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 controls over financial reporting.

/s/ WILLIAM W. DAVIS

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

Date: February 28, 2007

Exhibit 32.1

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

In connection with the Annual Report of Crosstex Energy, Inc. (the "Registrant") on Form 10-K for the year ended December 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned, Barry E. Davis, Chief Executive Officer of Crosstex Energy, Inc. and William W. Davis, Chief Financial Officer of Crosstex Energy Inc. certifies, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

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

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

Date: February 28, 2007

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

Date: February 28, 2007

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

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