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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (date of earliest event reported): January 26, 2010

CROSSTEX ENERGY, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**000-50067**	**16-1616605**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

2501 CEDAR SPRINGS DALLAS, TEXAS	**75201**
(Address of Principal Executive Offices)	(Zip Code)

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

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

On August 6, 2009, Crosstex Energy Services, L.P. and Crosstex Energy Services GP, LLC (collectively, the "Sellers"), subsidiaries of Crosstex Energy, L.P. (the "Partnership"), completed the sale of the Partnership's Mississippi, Alabama and south Texas assets, consisting of all of the partnership interests of certain Crosstex entities holding such assets to Southcross Energy LLC for an amount in cash equal to approximately $218.0 million, subject to further post-closing adjustments.

On October 1, 2009, the Sellers completed the sale of the Partnership's natural gas treating business, consisting of all of the partnership interests of Crosstex Treating Services, L.P. to KM Treating GP LLC, a subsidiary of Kinder-Morgan Energy Partners, L.P. for an amount in cash equal to approximately $265.4 million, subject to further post-closing adjustments.

A reclassification of letter of credit fees for the comparative periods presented in the Consolidated Statements of Operations was made to move the expense from purchased gas to interest expense for a better presentation of financing costs of the business. See discussion in the notes to the financial statements.

In addition to the changes noted above, recently adopted accounting standards requiring retrospective application have been applied to conform with generally accepted accounting principles. These changes are also discussed in the notes to the financial statements.

Accordingly, the Partnership has recast certain information included in the following items in its 2008 Annual Report on Form 10-K (the "2008 Annual Report") filed with the Securities and Exchange Commission ("SEC") on March 2, 2009 to reflect the Mississippi, Alabama and south Texas assets and the natural gas treating business as discontinued operations and letter of credit fees as interest expense for all periods presented**:**

- Item 6. Selected Financial Data;
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations;
- Item 7A. Quantitative and Qualitative Disclosures about Market Risk; and
- Item 8. Financial Statements and Supplementary Data.

The recast financial information of the Partnership is filed as Exhibits 99.1 through 99.4 to this Current Report on Form 8-K (the "Report") and is incorporated herein by reference. Except with respect to the limited matters described above or as expressly noted in the exhibits to this Report, the recast information included in this Report has not been updated to reflect events subsequent to the filing of the 2008 Annual Report. This Report should be read together with the portions of the 2008 Annual Report that they supplement, and together with the Partnership's Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2009, June 30, 2009 and September 30, 2009 and other Current Reports on Form 8-K filed by the Partnership with the SEC after the 2008 Annual Report.

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits.*

EXHIBIT NUMBER		DESCRIPTION
23.1	—	Consent of KPMG LLP
99.1	—	Selected Financial Data
99.2	—	Management's Discussion and Analysis of Supplemental Financial Condition and Results of Operations
99.3	—	Quantitative and Qualitative Disclosures about Market Risk
99.4	—	Supplemental Consolidated Financial Statements of Crosstex Energy, L.P.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

CROSSTEX ENERGY, L.P.

By: Crosstex Energy GP, L.P., its General Partner

By: Crosstex Energy GP, LLC, its General Partner

Date: January 26, 2010

By: /s/ William W. Davis
William W. Davis
Executive Vice President and
Chief Financial Officer

INDEX TO EXHIBITS

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Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.

We consent to the incorporation by reference in the registration statements No. 333-107025, 333-127645, and 333-159140 on Forms S-8 of Crosstex Energy, L.P. and subsidiaries of our reports dated March 2, 2009 except for Notes 2, 3, 8, 9, 13, 16, 17, and 18, which are as of January 26, 2010, with respect to the consolidated balance sheets of Crosstex Energy, L.P. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in partners' equity, comprehensive income, and cash flows for each of the years in the three-year period ended December 31, 2008, the related financial statement schedule, and the effectiveness of internal control over financial reporting as of December 31, 2008, which reports appear in this Current Report on Form 8-K of Crosstex Energy, L.P. and subsidiaries.

Dallas, TX
January 26, 2010

Item 6. *Selected Financial Data*

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

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

	Crosstex Energy, L.P. Years Ended December 31,				
	2008	2007	2006	2005	2004
	(In thousands, except per unit data)				
Statement of Operations Data:					
Revenues:					
Midstream	$ 3,072,646	$ 2,380,224	$ 1,534,800	$ 1,212,864	$ 790,692
Profit on energy trading activities	3,365	4,105	2,535	1,599	2,228
Total revenues	3,076,011	2,384,329	1,537,335	1,214,463	792,920
Operating costs and expenses:					
Purchased gas	2,768,225	2,124,503	1,378,979	1,154,345	756,820
Operating expenses	125,754	91,202	65,871	28,958	12,085
General and administrative	68,864	59,493	43,710	30,693	19,724
Gain on sale of property	(947)	(1,024)	(1,936)	(8,289)	(12)
(Gain) loss on derivatives	(8,619)	(4,147)	(174)	10,399	(206)
Impairments	29,373	—	—	—	—
Depreciation and amortization	107,521	83,315	56,349	15,122	6,520
Total operating costs and expenses	3,090,171	2,353,342	1,542,799	1,231,228	794,931
Operating income (loss)	(14,160)	30,987	(5,464)	(16,765)	(2,011)
Other income (expense):					
Interest expense, net	(74,971)	(48,059)	(19,889)	(12,407)	(5,861)
Loss on extinguishment of debt	—	—	—	—	—
Other income	27,770	538	212	392	786
Total other income (expense)	(47,201)	(47,521)	(19,677)	(12,015)	(5,075)
Loss from continuing operations before non-controlling interest and income taxes	(61,361)	(16,534)	(25,141)	(28,780)	(7,086)
Income tax provision	(2,369)	(760)	(222)	(216)	(162)
Loss from continuing operations, net of tax	(63,730)	(17,294)	(25,363)	(28,996)	(7,248)
Income from discontinued operations, net of tax	25,007	31,343	20,714	48,637	31,241
Gain from sale of discontinued operations, net of tax	49,805	—	—	—	—
Discontinued operations	74,812	31,343	20,714	48,637	31,241
Net income (loss) before cumulative effect of change in accounting principle	11,082	14,049	(4,649)	19,641	23,993
Cumulative effect of change in accounting principle	—	—	689	—	—
Net income (loss)	11,082	14,049	(3,960)	19,641	23,993
Less: Net income from continuing operations attributable to the non-controlling interest	311	160	231	441	289
Net income (loss) attributable to Crosstex Energy, L.P.	$ 10,771	$ 13,889	$ (4,191)	$ 19,200	$ 23,704
Net income (loss) per limited partner common unit	$ (3.19)	$ (0.20)	$ (1.09)	$ 0.56	$ 0.98
Net income per limited partner senior subordinated unit	$ 9.44	$ —	$ 5.31	$ —	$ —
Distributions declared per limited partner unit (1)	$ 2.00	$ 2.33	$ 2.18	$ 1.93	$ 1.70
Balance Sheet Data (end of period):					
Working capital deficit	$ (32,910)	$ (46,888)	$ (79,936)	$ (11,681)	$ (34,724)
Property and equipment, net	1,527,280	1,425,162	1,105,813	667,142	324,730
Total assets	2,533,266	2,592,874	2,194,474	1,425,158	586,771
Long-term debt	1,263,706	1,223,118	987,130	522,650	148,700
Partners' equity including non-controlling interest	797,931	788,641	715,531	405,559	147,096
Cash Flow Data:					
Net cash flow provided by (used in)(2):					
Operating activities	$ 173,750	$ 114,818	$ 113,010	$ 14,010	$ 48,103
Investing activities	(186,810)	(411,382)	(885,825)	(615,017)	(124,371)
Financing activities	14,554	295,882	772,234	596,615	81,899
Other Financial Data:					
Gross margin (3)	$ 307,786	$ 259,826	$ 158,356	$ 60,118	$ 36,100
Operating Data:					
Pipeline throughput (MMBtu/d)	1,991,000	1,555,000	845,000	582,000	667,000
Natural gas processed (MMBtu/d)(4)	1,608,000	1,835,000	1,817,000	1,707,000	286,000
Producer Services (MMBtu/d)	85,000	94,000	138,000	111,010	210,000

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

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

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

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

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

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

Overview

We are a Delaware limited partnership formed on July 12, 2002 to indirectly acquire substantially all of the assets, liabilities and operations of our predecessor, Crosstex Energy Services, Ltd. Historically, we have operated two industry segments, Midstream and Treating, with a geographic focus along the Texas Gulf Coast, in the north Texas Barnett Shale area, and in Louisiana and Mississippi. The recast of our 2008 10-K filing reflects the change in our business due to disposition of assets in 2009. In February 2009, we sold our Oklahoma assets; in August 2009 we sold our Alabama, Mississippi and south Texas Midstream properties and in October 2009 we sold our Treating assets. Our primary focus for our continuing operations is on the gathering, processing, transmission and marketing of natural gas and NGLs, as well as providing certain producer services. Currently, our geographic focus is in the north Texas Barnett Shale area and in Louisiana. We manage our operations by focusing on gross margin because our business is generally to purchase and resell natural gas for a margin, or to gather, process, transport and market natural gas or NGLs for a fee. We buy and sell most of our natural gas at a fixed relationship to the relevant index price. In addition, we receive certain fees for processing based on a percentage of the liquids produced and enter into hedge contracts for our expected share of the liquids produced to protect our margins from changes in liquids prices.

During the past five years we have grown significantly as a result of our construction and acquisition of gathering and transmission pipelines and treating and processing plants. From January 1, 2004 through December 31, 2008, we have invested over $2.3 billion to develop or acquire new assets. The purchased assets were acquired from numerous sellers at different periods and were accounted for under the purchase method of accounting. Subsequent to the filing of the annual report on Form 10-K for the period ended December 31, 2008 (the "2008 10-K"), we disposed of certain non-strategic assets as noted in the paragraph above. The financial information presented in this revised filing aggregate the results of operations of the 2009 dispositions into discontinued operations for the calculation of net income. Additionally, letter of credit fees have been reclassified to interest expense for a better analysis of financing costs. Accordingly, the results of operations for such acquisitions are included in our financial statements only from the applicable date of the acquisition and the results of operations from assets disposed of are in discontinued operations. As a consequence, the historical results of operations for the periods presented may not be comparable.

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

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

We generally gather or transport gas owned by others through our facilities for a fee, or we buy natural gas from a producer, plant or shipper at either a fixed discount to a market index or a percentage of the market index, then transport and resell the natural gas. In our purchase/sale transactions, the resale price is generally based on the same index price at which the gas was purchased, and, if we are to be profitable, at a smaller discount or larger premium to the index than it was purchased. We attempt to execute all purchases and sales substantially concurrently, or we enter into a future delivery obligation, thereby establishing the basis for the margin we will receive for each natural gas transaction. Our gathering and transportation margins related to a percentage of the index price can be adversely affected by declines in the price of natural gas.

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

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

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

Recent Developments

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

In addition, our business has been significantly impacted by the substantial decline in crude oil prices during the last half of 2008 from a high of approximately $145 per Bbl in July 2008 to a low of approximately $34 per Bbl in December 2008 (based on NYMEX futures daily close prices for the prompt month), a 76.7% decline, and the related 78.2% decline in NGL prices from a high of $2.19 per gallon in July 2008 to a low of $0.48 per gallon in December 2008 (based on the OPIS Mt. Belvieu daily average spot liquids prices). Crude oil prices reflected on NYMEX during January and February 2009 have fluctuated, to a lesser extent, between $49 per Bbl and $35 per Bbl while the OPIS Mt. Belvieu NGL prices have improved slightly ranging from $0.81 per gallon and $0.62 per gallon. The declines in NGL prices have negatively impacted our gross margin for the fourth quarter of 2008 and could continue to negatively impact our gross margin (revenue less cost of gas purchases) in 2009. A significant percentage of inlet gas at our processing plants is settled under POL agreements or margin contracts. Over the past two years the inlet processing volumes associated with POL and margin contracts were approximately 70%, on a combined basis, of the total volume of gas processed. The POL fees are denominated in the form of a share of the liquids extracted. Therefore, fee revenue under a POL agreement is directly impacted by NGL prices and the decline of these prices in 2008 contributed to a significant decline in gross margin from processing. Under the POL settlement terms, we are not responsible for the fuel or shrink associated with processing. Under margin contracts we realize a gross margin from processing based upon the difference in the value of NGLs extracted from the gas less the value of the product in its gaseous state and the cost of fuel to extract. This is often referred to as the fractionation spread. During the last half of 2008 the “fractionation spread” narrowed significantly as the value of NGLs decreased more than the value of the gas and fuel associated with the processed gas. Thus the gross margin realized under these margin contracts was also negatively impacted due to the commodity price environment. If the current weakness in the economy continues for a prolonged period, it would likely further reduce demand for gas and for NGL products, such as ethane, a primary feedstock for the petrochemical and manufacturing industries, and result in continued lower natural gas and NGL prices. Although we have seen some improvement in NGL prices and the fractionation spread in the early months of 2009 over the levels experienced in December 2008, we believe that our processing margins in 2009 will be substantially lower than the processing margins realized in 2008 based on current market indicators. For the year ended December 31, 2008, approximately 42.4% of our gross margin was attributable to gas processing as compared to 54.9% of our gross margin for the year ended December 31, 2007. See Item 7A, “Quantitative and Qualitative Disclosures about Market Risk-Commodity Price Risk” for a description of our contractual processing arrangements.

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

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

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

Acquisitions and Expansion

We have grown significantly through asset purchases and construction and expansion projects in recent years. This growth creates many of the major differences when comparing operating results from one period to another. The most significant asset purchases since January 2006 were the acquisition of midstream assets from Chief Holdings, LLC, or Chief, in June 2006, the Hanover Compression Company treating assets in February 2006 and the amine-treating business of Cardinal Gas Solutions L.P. in October 2006. The Hanover and Cardinal assets were included in the disposition of Treating assets in 2009. As a result, the income from these assets is included in discontinued operations. In addition, internal expansion projects in north Texas and Louisiana have contributed to the increase in our business during 2006, 2007 and 2008.

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

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

On February 1, 2006, we acquired 48 amine treating plants from a subsidiary of Hanover Compression Company for $51.7 million. These assets were sold in October 2009 as part of the Treating assets.

On October 3, 2006, we acquired the amine-treating business of Cardinal Gas Solutions L.P. for $6.3 million. The acquisition added 10 dew point control plants and 50% of seven amine-treating plants to our plant portfolio. On March 28, 2007, we acquired the remaining 50% interest in the amine-treating plants for approximately $1.5 million. These assets were sold in October 2009 as part of the Treating assets.

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

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

Commodity Price Risk

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

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

We are also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transportation services. Approximately 3.0% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices.

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

Results of Operations

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

	Years Ended December 31,		
	2008	2007	2006
		(Dollars in millions)	
Midstream revenues	$ 3,072.6	$ 2,380.2	$ 1,534.8
Purchased gas	(2,768.2)	(2,124.5)	(1,378.9)
Profits on energy trading activities	3.4	4.1	2.5
Total gross margin	$ 307.8	$ 259.8	$ 158.4
Volumes (MMBtu/d):			
Gathering and transportation	1,991,000	1,555,000	845,000
Processing	1,608,000	1,835,000	1,817,000
Producer services	85,000	94,000	138,000

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

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $307.8 million for the year ended December 31, 2008 compared to $259.8 million for the year ended December 31, 2007, an increase of $48.0 million, or 18.5%. The increase was primarily due to system expansion projects and increased throughput on our gathering and transmission systems. These increases were partially offset by margin decreases in the processing business due to a less favorable NGL market and operating downtime due to the impact of hurricanes in the last half of the year. Profit on energy trading activities decreased for the comparative periods by approximately $0.7 million.

System expansion in the north Texas region and increased throughput on the NTP contributed $58.9 million of gross margin growth for the year ended December 31, 2008 over the same period in 2007. The gathering systems in the region and NTP accounted for $41.3 million and $9.1 million of this increase, respectively. The processing facilities in the region contributed an additional $8.5 million of gross margin increase. System expansion and volume increases on the LIG system contributed margin growth of $8.2 million during the year ended December 31, 2008 over the same period in 2007. Processing plants in Louisiana experienced a margin decline of $20.2 million for the comparative twelve-month period in 2008 due to a less favorable NGL processing environment in the last half of the year and business interruptions due to the impact of hurricanes along the Gulf Coast.

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

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

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

- $0.7 million in technical services operating expense.

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

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

Gain/Loss on Derivatives. We had a gain on derivatives of $8.6 million for the year ended December 31, 2008 compared to a gain of $4.1 million for the year ended December 31, 2007. The derivative transaction types contributing to the net gain are as follows (in millions):

	Years Ended December 31,			
	2008		2007	
(Gain)/Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ (8.7)	$ (8.8)	$ (8.1)	$ (7.0)
Processing margin hedges	(3.6)	(3.6)	1.3	1.3
Storage	(0.7)	(0.1)	(0.5)	(1.6)
Third-party on-system swaps	(0.6)	(0.8)	(0.2)	(0.6)
Puts	—	—	0.8	—
Other	(0.1)	—	0.1	—
	$ (13.7)	$ (13.3)	$ (6.6)	$ (7.9)
Adjusted for derivative gains included in income from discontinued operations	5.1	5.4	2.5	2.8
	$ (8.6)	$ (7.9)	$ (4.1)	$ (5.1)

Gain/Loss on Sale of Property. Assets sold during the year ended December 31, 2008 generated a net gain of $0.9 million as compared to a gain of $1.0 million during the year ended December 31, 2007. The 2008 gain was primarily generated from the disposition of various small Midstream assets. The 2007 gain was primarily generated from the disposition of unused catalyst material.

Impairments. During the year ended December 31, 2008, we had an impairment expense of $29.4 million compared to no impairment expense for the year ended December 31, 2007. The impairment expense is comprised of:

- $17.8 million related to the Blue Water gas processing plant located in south Louisiana — The impairment on our 59.27% interest in the Blue Water gas processing plant was recognized because the pipeline company which owns the offshore Blue Water system and supplies gas to our Blue Water plant reversed the flow of the gas on its pipeline in early January 2009 thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system. As of January 2009, we had not found an alternative source of new gas for the Blue Water plant so the plant ceased operation from January 2009 until November 2009. An impairment of $17.8 million was recognized for the carrying amount of the plant in excess of the estimated fair value of the plant as of December 31, 2008.
- $4.9 million related to goodwill — We determined that the carrying amount of goodwill attributable to the Midstream segment was impaired because of the significant decline in our Midstream operations due to negative impacts on cash flows caused by the significant declines in natural gas and NGL prices during the last half of 2008 coupled with the global economic decline.
- $4.1 million related to leasehold improvements — We had planned to relocate our corporate headquarters during 2008 to a larger office facility. We had leased office space and were close to completing the renovation of this office space when the global economic decline began impacting our operations in October 2008. On December 31, 2008,

the decision was made to cancel the new office lease and not relocate the corporate offices from its existing office location. The impairment relates to the leasehold improvements on the office space for the cancelled lease.

- $2.6 million related to the Arkoma gathering system — The impairment on the Arkoma gathering system was recognized because we sold this asset in February 2009 for $11.0 million and the carrying amount of the plant exceeded the sale price by approximately $2.6 million.

Depreciation and Amortization. Depreciation and amortization expenses were $107.5 million for the year ended December 31, 2008 compared to $83.3 million for the year ended December 31, 2007, an increase of $24.2 million, or 29.1%. Depreciation and amortization increased $22.5 million due to the NTP, NTG and north Louisiana expansion project assets. Accelerated depreciation of the Dallas office leasehold due to the planned, but subsequently cancelled, relocation accounted for an increase between periods of $1.4 million.

Interest Expense. Interest expense was $75.0 million for the year ended December 31, 2008 compared to $48.1 million for the year ended December 31, 2007, an increase of $26.9 million, or 56.0%. The increase relates primarily to the negative impact of declining interest rates on our interest rate swaps. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2008	2007
Senior notes	$ 22.5	$ 23.0
Credit facility	20.8	24.8
Capitalized interest	(2.7)	(4.8)
Mark to market interest rate swaps	22.1	1.2
Realized interest rate swaps	4.6	(0.7)
Interest income	(0.3)	(0.7)
Other	8.0	5.3
Total	$ 75.0	$ 48.1

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

Other Income. Other income was $27.8 million for the year ended December 31, 2008 compared to $0.5 million for the year ended December 31, 2007. In November 2008, the Partnership sold a contract right for firm transportation capacity on a third party pipeline to an unaffiliated third party for $20.0 million. The entire amount of such proceeds is reflected in other income because the Partnership had no basis in this contract right. In February 2008, the Partnership recorded $7.0 million from the settlement of disputed liabilities that were assumed with an acquisition.

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

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

Gross Margin and Profit on Energy Trading Activities. Midstream gross margin was $259.8 million for the year ended December 31, 2007 compared to $158.4 million for the year ended December 31, 2006, an increase of $101.5 million, or 64.1%. This increase was primarily due to system expansions, increased system throughput and a favorable processing environment for natural gas and NGLs.

Crosstex acquired the NTG assets from Chief in June 2006. System expansion in the North Texas region and increased throughput on the NTP contributed $64.5 million of gross margin growth during the twelve months ended December 31, 2007 over the same period in 2006. The NTG and NTP assets accounted for $34.1 million and $16.6 million of this increase, respectively. The processing facilities in the region contributed an additional $13.3 million of this gross margin increase. Operational improvements, system expansion and increased volume on the LIG system coupled with optimization and integration with the south Louisiana processing assets contributed margin growth of $22.6 million for 2007. The Eastern region plant group contributed margin growth of $9.9 million due to a favorable gas processing environment.

The favorable processing margins we realized during 2007 at several of our processing facilities may be higher than margins we may realize during 2008 and future periods if the NGL markets do not remain as strong as they were during 2007. As discussed above under "— Commodity Price Risk", we receive 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 2007, we experience higher processing margins. We have the ability to bypass certain volumes when processing is uneconomic so we can limit our exposure to adverse processing margins but our processing margins will be lower during these periods.

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

Operating Expenses. Operating expenses were $91.2 million for the year ended December 31, 2007 compared to $65.9 million for the year ended December 31, 2006, an increase of $25.3 million, or 38.5%. The increase in operating expenses primarily reflects costs associated with growth and expansion in the north Texas assets of $17.5 million, LIG and the north Louisiana expansion of $3.4 million. Operating expenses included $1.8 million of stock-based compensation expense in 2007 compared to $1.1 million of stock-based compensation expense in 2006.

General and Administrative Expenses. General and administrative expenses were $59.5 million for the year ended December 31, 2007 compared to $43.7 million for the year ended December 31, 2006, an increase of $15.8 million, or 36.1%. Additions to headcount associated with the requirements of NTP and NTG assets and the expansion in north Louisiana accounted for $8.9 million of the increase. Consulting for system and process improvements resulted in $2.8 million of the increase. General and administrative expenses included stock-based compensation expense of $10.2 million and $7.4 million in 2007 and 2006, respectively.

Gain/Loss on Derivatives. We had a gain on derivatives of $4.1 million for the year ended December 31, 2007 compared to a gain of $0.2 million for the year ended December 31, 2006. The derivative transaction types contributing to the net gain are as follows (in millions):

	Years Ended December 31,			
	2007		2006	
(Gain) Loss on Derivatives:	**Total**	**Realized**	**Total**	**Realized**
Basis swaps	$ (8.1)	$ (7.0)	$ (0.7)	$ (0.4)
Processing margin hedges	1.3	1.3	—	—
Storage	(0.5)	(1.6)	(2.9)	(0.7)
Third-party on-system swaps	(0.2)	(0.6)	(1.5)	(1.2)
Puts	0.8	—	3.6	—
Other	0.1	—	(0.1)	—
	$ (6.6)	$ (7.9)	$ (1.6)	$ (2.3)
Adjusted for derivative gains included in income from discontinued operations	2.5	2.8	1.4	1.0
	$ (4.1)	$ (5.1)	$ (0.2)	$ (1.3)

Gain/Loss on Sale of Property. Assets sold during the year ended December 31, 2007 generated a net gain of $1.0 million as compared to a gain of $1.9 million during the year ended December 31, 2006. The 2007 gain was primarily generated from the disposition of unused catalyst material. The gain in 2006 primarily related to the sale of inactive gas processing facilities acquired as a part of the south Louisiana processing assets and as part of LIG acquisition.

Depreciation and Amortization. Depreciation and amortization expenses were $83.3 million for the year ended December 31, 2007 compared to $56.3 million for the year ended December 31, 2006, an increase of $27.0 million, or 47.9%. Depreciation and amortization increased $26.3 million due to the NTP, NTG and north Louisiana expansion project assets.

Interest Expense. Interest expense was $48.1 million for the year ended December 31, 2007 compared to $19.9 million for the year ended December 31, 2006, an increase of $28.2 million, or 142.0%. The increase relates primarily to an increase in debt outstanding as a result of acquisitions and other growth projects. Net interest expense consists of the following (in millions):

	Years Ended December 31,	
	2007	2006
Senior notes	$ 23.0	$ 13.3
Credit facility	24.8	7.9
Capitalized interest	(4.8)	(5.4)
Mark to market interest rate swaps	1.2	(0.1)
Realized interest rate swaps	(0.7)	—
Interest income	(0.7)	(1.1)
Other	5.3	5.3
Total	$ 48.1	$ 19.9

Discontinued Operations. Income from discontinued operations was $31.3 million for the year ended December 31, 2007 compared to $20.7 million for the year ended December 31, 2006. Discontinued operations includes income related to the Seminole gas processing plant disposed of in November 2008, income related to the Alabama, Mississippi and south Texas assets disposed of in August 2009 and income related to the Treating assets disposed of in October 2009. The reported income for the comparative periods has been recast to include 2009 dispositions in income from discontinued operations.

Critical Accounting Policies

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

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

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

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

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

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

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

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

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

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

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

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

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

Liquidity and Capital Resources

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

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

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

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

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

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

Net cash invested in Midstream assets was $222.4 million for 2008, $385.8 million for 2007 and $746.7 million for 2006 (including $475.4 million related to the acquisition of assets from Chief). Net cash invested in Treating assets was $41.8 million for 2008, $23.5 million for 2007 and $86.8 million for 2006 (including $51.5 million related to the acquisition of Hanover assets which were sold in October 2009). Net cash invested in other corporate assets was $11.4 million for 2008, $5.2 million for 2007 and $8.2 million for 2006.

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

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

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

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

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

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

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

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

Working Capital Deficit. We had a working capital deficit of $32.9 million as of December 31, 2008, primarily due to drafts payable of $21.5 million as of the same date. Our changes in working capital may fluctuate significantly between periods even though our trade receivables and payables are typically collected and paid in 30 to 60 day pay cycles. A large volume of our revenues are collected and a large volume of our gas purchases are paid near each month end or the first few days of the following month so receivable and payable balances at any month end my fluctuate significantly depending on the timing of these receipts and payments. In addition, although we strive to minimize our natural gas and NGLs in inventory, these working inventory balances may fluctuate significantly from period to period due to operational reasons and due to changes in natural gas and NGL prices. Our working capital also includes our mark to market derivative assets and liabilities associated with our commodity derivatives which may fluctuate significantly due to the changes in natural gas and NGL prices and associated with our interest rate swap derivatives which may fluctuate significantly due to changes in interest rates. The changes in working capital during the years ended December 31, 2008, 2007 and 2006 are due to the impact of the fluctuations discussed above.

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

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

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

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

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

Sources of Liquidity in 2009 and Capital Requirements

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

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

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

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

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

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

	Payments Due by Period						
	Total	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**
Long-Term Debt	$ 1,263.7	$ 9.4	$ 20.3	$ 816.0	$ 93.0	$ 93.0	$ 232.0
Interest Payable on Fixed Long-Term Debt Obligations	194.6	38.0	37.0	35.6	31.3	23.9	28.8
Capital Lease Obligations	32.8	3.3	3.2	3.2	3.2	3.2	16.7
Operating Leases	86.5	27.2	18.5	17.7	16.3	3.1	3.7
Unconditional Purchase Obligations	13.5	13.5	—	—	—	—	—
FIN 48 Tax Obligations	1.6	1.3	0.1	0.1	0.1	—	—
Total Contractual Obligations	$ 1,592.7	$ 92.7	$ 79.1	$ 872.6	$ 143.9	$ 123.2	$ 281.2

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

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

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

Description of Indebtedness

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

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

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

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

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

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

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

(a) The applicable margins for the bank reference rate advances ranged from 0% to 0.25% under the bank credit facility prior to the Fifth and Sixth Amendments. The applicable margin for the bank reference rate advances was paid at the maximum rate of

2.00% under the Fifth Amendment from the November 7, 2008 until February 27, 2009.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We are subject to interest rate risk on our credit facility and have entered into interest rate swaps to reduce this risk.

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

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

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

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

On November 7, 2008, we amended our senior secured note agreement governing our senior secured notes to, among other things, (i) modify the maximum permitted leverage ratio and lower the minimum interest coverage ratio we must maintain consistent with the ratios under the Fifth Amendment to the bank credit facility, (ii) permit us to sell certain assets and (iii) increase the interest rate we pay on the senior secured notes. The interest rate we paid on the senior secured notes increased by 1.25% for the fourth quarter of 2008 due to this amendment.

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

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

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

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

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

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

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

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

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

Credit Risk

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

Inflation

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

Environmental

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

Contingencies

On November 15, 2007, Crosstex Processing received a demand letter from Denbury asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. The claim arises from a contract under which Crosstex Processing processed natural gas owned or controlled by Denbury in north Texas. Denbury contends that Crosstex Processing breached the Processing Contract by failing to build a processing plant of a certain size and design, resulting in Crosstex Processing's failure to properly process the gas over a ten month period. Denbury also alleges that Crosstex Processing failed to provide specific notices required under the Processing Contract. On December 4, 2007 and again on February 14, 2008, Denbury sent Crosstex Processing letters demanding that its claim be arbitrated pursuant to an arbitration provision in the Processing Contract. On April 15, 2008, the parties mediated the matter unsuccessfully. On December 4, 2008, Denbury initiated formal arbitration proceedings against Crosstex Processing, Crosstex Energy Services, L.P., Crosstex North Texas Gathering, L.P., and Crosstex Gulf Coast Marketing, Ltd., seeking $11.4 million and additional unspecified damages. On December 23, 2008, Crosstex Processing filed an answer denying Denbury's allegations and a counterclaim seeking a declaratory judgment that its processing plant is uneconomic pursuant to the terms of the Processing Contract, allowing cancellation of the contract. Crosstex Energy, Crosstex Marketing, and Crosstex Gathering also filed an answer denying Denbury's allegations and asserting that they are improper parties as Denbury's claim is for breach of the Processing Contract and none of these entities is a party to that agreement. Crosstex Gathering also filed a counterclaim seeking approximately $40.0 million in damages for the value of the NGLs it is entitled to under its Gas Gathering Agreement with Denbury. Once the three-person arbitration panel has been named and cleared conflicts, the arbitration panel will hold a preliminary conference with the parties to set a date for the final hearing and other case deadlines and to establish discovery limits. Although it is not possible to predict with certainty the ultimate outcome of this matter, we do not believe this will have a material adverse effect on our consolidated results of operations or financial position.

The Partnership (or its subsidiaries) is defending eleven lawsuits filed by owners of property located near processing facilities or compression facilities constructed by us as part of our systems in north Texas. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. At this time, five cases are set for trial during 2009. The remaining cases have not yet been set for trial. Discovery is underway. Although it is not possible to predict the ultimate outcomes of these matters, we do not believe that these claims will have a material adverse impact on our consolidated results of operations or financial condition.

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

Recent Accounting Pronouncements

As a result of the recent credit crisis, FASB ASC 820-10-35-15A was issued October 2008 and clarifies the application of FASB ASC 820 in a market that is not active and provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. FASB ASC 820-10-35-15A is effective upon issuance, for companies that have adopted FASB ASC 820. The Partnership has evaluated FASB ASC 820-10-35-15A and determined that this standard has no impact on its results of operations, cash flows or financial position for this reporting period.

FASB ASC 260-10-45-60 was issued June 2008 and requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB ASC 260. FASB

ASC 260-10-45-60 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Upon adoption, the Partnership will consider restricted shares with nonforfeitable dividend rights in the calculation of earnings per share and will adjust all prior reporting periods retrospectively to conform to the requirements, although the impact should not be material.

FASB ASC 825-10-05-5 was issued February 2007 and permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. FASB ASC 825-10-05-5 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. FASB ASC 825-10-05-5 was adopted effective January 1, 2008 and did not have a material impact on our financial statements.

FASB ASC 805 and FASB ASC 810-10-65-1 were issued December 2007. FASB ASC 805 requires most identifiable assets, liabilities, noncontrolling interests and goodwill acquired in a business combination to be recorded at "full fair value." The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under FASB ASC 805 all business combinations will be accounted for by applying the acquisition method. FASB ASC 805 is effective for periods beginning on or after December 15, 2008. FASB ASC 810-10-65-1 will require noncontrolling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for noncontrolling interests and transactions with noncontrolling interest holders in consolidated financial statements. FASB ASC 810-10-65-1 is effective for periods beginning on or after December 15, 2008 and will be applied prospectively to all noncontrolling interests, including any that arose before the effective date, except that comparative period information must be recast to classify noncontrolling interests in equity, attribute net income and other comprehensive income to noncontrolling interests and provide other disclosures required by FASB ASC 810-10-65-1.

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

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

FASB ASC 815-10-65-1 was issued March 2008 and requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under FASB ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. FASB ASC 815-10-65-1 is effective for fiscal years beginning after November 15, 2008. The principal impact to the Partnership will be to require expanded disclosure regarding derivative instruments.

Disclosure Regarding Forward-Looking Statements

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

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

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

Interest Rate Risk

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

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

Commodity Price Risk

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

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

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

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

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

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

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

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

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

We are also subject to price risk to a lesser extent for fluctuations in natural gas prices with respect to a portion of our gathering and transport services. Approximately 3.0% of the natural gas we market is purchased at a percentage of the relevant natural gas index price, as opposed to a fixed discount to that price. As a result of purchasing the natural gas at a percentage of the index price, our resale margins are higher during periods of high natural gas prices and lower during periods of lower natural gas prices. We have hedged 34% of our natural gas volumes at risk through the end of 2009.

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

	Years Ended December 31, 2008			
	Gas Purchased		Gas Sold	
Asset or Business	Fixed Amount to Index	Percentage of Index	Fixed Amount to Index	Percentage of Index
	(In thousands of MMBtu's)			
LIG system(2)	248,715	3,955	252,670	—
North Texas system	84,311	4,577	88,889	—
Other assets and activities(1)	78,374	2,160	52,511	—

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

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

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

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

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

As of December 31, 2008, outstanding natural gas swap agreements, NGL swap agreements, swing swap agreements, storage swap agreements and other derivative instruments were a net fair value asset of $16.0 million. The aggregate effect of a hypothetical 10% increase in gas and NGLs prices would result in a decrease of approximately $1.4 million in the net fair value asset of these contracts as of December 31, 2008.

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

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

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

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

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

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

Dallas, Texas
March 2, 2009, except for Notes 2, 3, 8, 9, 13, 16, 17, and 18,
which are as of January 26, 2010

Report of Independent Registered Public Accounting Firm

The Partners
Crosstex Energy, L.P.:

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

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

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

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

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

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

/s/ KPMG LLP

Dallas, Texas
March 2, 2009

CROSSTEX ENERGY, L.P.

Consolidated Balance Sheets

	December 31, 2008	December 31, 2007
	(In thousands except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,636	$ 142
Accounts receivable:		
Trade, net of allowance for bad debts of $3,655 and $985, respectively	49,185	46,441
Accrued revenues	292,668	443,448
Imbalances	3,893	3,865
Affiliated companies	110	38
Note receivable	375	1,026
Other	7,243	2,531
Fair value of derivative assets	27,166	8,589
Natural gas and natural gas liquids, prepaid expenses and other	9,645	16,062
Total current assets	391,921	522,142
Property and equipment:		
Transmission assets	474,771	468,692
Gathering systems	614,572	460,420
Gas plants	577,250	565,415
Other property and equipment	70,618	64,073
Construction in process	86,462	79,889
Total property and equipment	1,823,673	1,638,489
Accumulated depreciation	(296,393)	(213,327)
Total property and equipment, net	1,527,280	1,425,162
Fair value of derivative assets	4,628	1,337
Intangible assets, net of accumulated amortization of $89,231 and $60,118, respectively	578,096	610,076
Goodwill	19,673	24,540
Other assets, net	11,668	9,617
Total assets	$ 2,533,266	$ 2,592,874
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Drafts payable	$ 21,514	$ 28,931
Accounts payable	23,879	13,727
Accrued gas purchases	270,229	427,293
Accrued imbalances payable	7,100	9,447
Fair value of derivative liabilities	28,506	21,066
Current portion of long-term debt	9,412	9,412
Other current liabilities	64,191	59,154
Total current liabilities	424,831	569,030
Long-term debt	1,254,294	1,213,706
Other long-term liabilities	24,708	3,553
Deferred tax liability	8,727	8,518
Fair value of derivative liabilities	22,775	9,426
Commitments and contingencies	—	—
Partners' equity:		
Common unitholders (44,908,522 and 23,868,041 units issued and outstanding at December 31, 2008 and 2007, respectively)	674,564	337,171
Subordinated unitholders (4,668,000 units issued and outstanding at December 31, 2007)	—	(14,679)
Senior subordinated series C unitholders (12,829,650 units issued and outstanding at December 31, 2007)	—	359,319
Senior subordinated series D unitholders (3,875,340 units issued and outstanding at December 31, 2008 and 2007)	99,942	99,942
General partner interest (2% interest with 995,556 and 923,286 equivalent units outstanding at December 31, 2008 and 2007)	16,805	24,551
Non-controlling interest	3,510	3,815
Accumulated other comprehensive income (loss)	3,110	(21,478)
Total partners' equity	797,931	788,641
Total liabilities and equity	$ 2,533,266	$ 2,592,874

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Operations

	Years Ended December 31, 2008	2007	2006
	(In thousands except per unit data)		
Revenues:			
Midstream	$ 3,072,646	$ 2,380,224	$ 1,534,800
Profit on energy trading activities	3,365	4,105	2,535
Total revenues	3,076,011	2,384,329	1,537,335
Operating costs and expenses:			
Purchased gas	2,768,225	2,124,503	1,378,979
Operating expenses	125,754	91,202	65,871
General and administrative	68,864	59,493	43,710
Gain on derivatives	(8,619)	(4,147)	(174)
Gain on sale of property	(947)	(1,024)	(1,936)
Impairments	29,373	—	—
Depreciation and amortization	107,521	83,315	56,349
Total operating costs and expenses	3,090,171	2,353,342	1,542,799
Operating income (loss)	(14,160)	30,987	(5,464)
Other income (expense):			
Interest expense, net of interest income	(74,971)	(48,059)	(19,889)
Other income	27,770	538	212
Total other income (expense)	(47,201)	(47,521)	(19,677)
Loss from continuing operations before non-controlling interest, income taxes and cumulative effect of change in accounting principle	(61,361)	(16,534)	(25,141)
Income tax provision	(2,369)	(760)	(222)
Loss from continuing operations net of tax before discontinued operations and cumulative effect of changes in accounting principle	(63,730)	(17,294)	(25,363)
Discontinued operations:			
Income from discontinued operations	25,007	31,343	20,714
Gain on sale of discontinued operations	49,805	—	—
Discontinued operations (net of tax)	74,812	31,343	20,714
Net income (loss) before cumulative effect of change in accounting principle	11,082	14,049	(4,649)
Cumulative effect of change in accounting principle	—	—	689
Net income (loss)	$ 11,082	$ 14,049	$ (3,960)
Less: Net income attributable to the non-controlling interest	311	160	231
Net income (loss) attributable to Crosstex Energy, L.P.	$ 10,771	$ 13,889	$ (4,191)
General partner interest in net income	$ 26,415	$ 19,252	$ 16,456
Limited partners' interest in net loss	$ (15,644)	$ (5,363)	$ (20,647)
Net income (loss) per limited partners' common unit:			
Basic and diluted common unit	$ (3.19)	$ (0.20)	$ (1.09)
Basic and diluted senior subordinated A units (see Note 9(e))	$ —	$ —	$ 5.31
Basic and diluted senior subordinated series C units (see Note 9(e))	$ 9.44	$ —	$ —
Basic and diluted senior subordinated series D units (see Note 9(e))	$ —	$ —	$ —

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

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

	Common Units		Subordinated Units		Sr. Subordinated Units		Sr. Subordinated C Units		Sr. Subordinated D Units		General Partner Interest		Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total
	$	Units	$	Units	$	Units	$	Units	$	Units	$	Units			
Balance, December 31, 2005	$ 326,617	15,465	$ 16,462	9,334	$ 49,921	1,495	$ —	—	$ —	—	$ 11,522	537	$ (3,237)	$ 4,274	$ 405,559
Proceeds from exercise of unit options	3,328	305	—	—	—	—	—	—	—	—	—	—	—	—	3,328
Issuance of Sr. subordinated series C units	—	—	—	—	—	—	359,319	12,830	—	—	—	—	—	—	359,319
Conversion of subordinated units	52,195	3,829	(2,274)	(2,333)	(49,921)	(1,495)	—	—	—	—	—	—	—	—	—
Conversion of common units for restricted units	—	17	—	—	—	—	—	—	—	—	—	—	—	—	—
Capital contributions	—	—	—	—	—	—	—	—	—	—	9,273	268	—	—	9,273
Stock-based compensation	3,122	—	1,114	—	—	—	—	—	—	—	3,632	—	—	—	7,868
Distributions	(39,725)	—	(16,102)	—	—	—	—	—	—	—	(20,411)	—	—	(850)	(77,088)
Net income (loss)	(15,045)	—	(5,602)	—	—	—	—	—	—	—	16,456	—	—	231	(3,960)
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	—	—	(4,875)	—	(4,875)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	16,108	—	16,108
Balance, December 31, 2006	330,492	19,616	(6,402)	7,001	—	—	359,319	12,830	—	—	20,472	805	7,996	3,655	715,532
Issuance of common units	57,550	1,800	—	—	—	—	—	—	—	—	—	—	—	—	57,550
Proceeds from exercise of unit options	1,598	90	—	—	—	—	—	—	—	—	—	—	—	—	1,598
Issuance of Sr. subordinated series D units	—	—	—	—	—	—	—	—	99,942	3,875	—	—	—	—	99,942
Conversion of subordinated units	(3,872)	2,333	3,872	(2,333)	—	—	—	—	—	—	—	—	—	—	—
Conversion of restricted units for common units, net of units withheld for taxes	(329)	29	—	—	—	—	—	—	—	—	—	—	—	—	(329)
Capital contributions	—	—		—	—	—	—	—	—	—	4,014	118	—	—	4,014
Stock-based compensation	5,478	—	1,228	—	—	—	—	—	—	—	5,578	—	—	—	12,284
Distributions	(49,810)	—	(11,950)	—	—	—	—	—	—	—	(24,765)	—	—	—	(86,525)
Net income (loss)	(3,936)	—	(1,427)	—	—	—	—	—	—	—	19,252	—	—	160	14,049
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	—	—	(3,706)	—	(3,706)
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	(25,768)	—	(25,768)
Balance December 31, 2007	337,171	23,868	(14,679)	4,668	—	—	359,319	12,830	99,942	3,875	24,551	923	(21,478)	3,815	788,641
Issuance of common units	99,888	3,333	—	—	—	—	—	—	—	—	—	—	—	—	99,888
Proceeds from exercise of unit options	850	57	—	—	—	—	—	—	—	—	—	—	—	—	850
Conversion of subordinated units	341,816	17,498	17,503	(4,668)	—	—	(359,319)	(12,830)	—	—	—	—	—	—	—
Conversion of restricted units for common units, net of units withheld for taxes	(1,536)	153	—	—	—	—	—	—	—	—	—	—	—	—	(1,536)
Capital contributions	—	—	—	—	—	—	—	—	—	—	2,193	73	—	109	2,302
Stock-based compensation	6,337	—	109	—	—	—	—	—	—	—	4,797	—	—	—	11,243
Distributions	(94,404)	—	(2,847)	—	—	—	—	—	—	—	(41,151)	—	—	(725)	(139,127)
Net income (loss)	(15,558)	—	(86)	—	—	—	—	—	—	—	26,415	—	—	311	11,082
Hedging gains or losses reclassified to earnings	—	—	—	—	—	—	—	—	—	—	—	—	20,840	—	20,840
Adjustment in fair value of derivatives	—	—	—	—	—	—	—	—	—	—	—	—	3,748	—	3,748
Balance December 31, 2008	$ 674,564	44,909	$ —	—	$ —	—	$ —	—	$ 99,942	3,875	$ 16,805	996	$ 3,110	$ 3,510	$ 797,931

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Comprehensive Income

	Years Ended December 31,		
	2008	2007	2006
		(In thousands)	
Net income (loss)	$ 11,082	$ 14,049	$ (3,960)
Hedging gains or losses reclassified to earnings	20,840	(3,706)	(4,875)
Adjustment in fair value of derivatives	3,748	(25,768)	16,108
Comprehensive income (loss)	35,670	(15,425)	7,273
Comprehensive income attributable to non-controlling interest	311	160	231
Comprehensive income (loss) attributable to Crosstex Energy, L.P.	$ 35,359	$(15,585)	$ 7,042

See accompanying notes to consolidated financial statements.

CROSSTEX ENERGY, L.P.

Consolidated Statements of Cash Flows

	Years Ended December 31, 2008	2007 (In thousands)	2006
Cash flows from operating activities:			
Net income (loss)	$ 11,082	$ 14,049	$ (3,960)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	132,899	108,880	82,731
Non-cash stock-based compensation	11,243	12,284	8,557
Cumulative effect of change in accounting principle	—	—	(689)
Gain on sale of property	(51,325)	(1,667)	(2,108)
Impairment	30,436	—	—
Deferred tax expense	172	253	490
Non-cash derivatives loss	23,510	2,418	550
Amortization of debt issue costs	2,854	2,639	2,694
Changes in assets and liabilities, net of acquisition effects:			
Accounts receivable, accrued revenue and other	156,248	(121,300)	77,365
Natural gas and natural gas liquids, prepaid expenses and other	5,176	(5,566)	13,071
Accounts payable, accrued gas purchases and other accrued liabilities	(148,545)	101,993	(65,691)
Fair value of derivatives	—	835	—
Net cash provided by operating activities	173,750	114,818	113,010
Cash flows from investing activities:			
Additions to property and equipment	(275,590)	(414,452)	(314,766)
Acquisitions and asset purchases	—	—	(576,110)
Proceeds from sales of property	88,780	3,070	5,051
Net cash used in investing activities	(186,810)	(411,382)	(885,825)
Cash flows from financing activities:			
Proceeds from borrowings	1,743,580	1,189,500	1,708,500
Payments on borrowings	(1,702,992)	(953,512)	(1,244,021)
Proceeds from capital lease obligations	28,010	3,553	—
Payments on capital lease obligations	(4,101)	—	—
Increase (decrease) in drafts payable	(7,417)	(19,017)	18,094
Debt refinancing costs	(4,903)	(892)	(5,646)
Conversion of restricted units, net of units withheld for taxes	(1,536)	(329)	—
Distributions to non-controlling interest	(725)	—	(375)
Distribution to partners	(138,402)	(86,525)	(76,238)
Proceeds from exercise of unit options	850	1,598	3,328
Net proceeds from common unit offerings	99,888	57,550	—
Issuance of subordinated units	—	99,942	359,319
Contribution from partners	2,193	4,014	9,273
Contributions from non-controlling interest	109	—	—
Net cash provided by financing activities	14,554	295,882	772,234
Net increase (decrease) in cash and cash equivalents	1,494	(682)	(581)
Cash and cash equivalents, beginning of period	142	824	1,405
Cash and cash equivalents, end of period	$ 1,636	$ 142	$ 824
Cash paid for interest	$ 76,291	$ 79,648	$ 46,794
Cash paid (refund) for income taxes	$ 1,371	$ 38	$ (847)

See accompanying notes to consolidated financial statements.

(1) Organization and Summary of Significant Agreements

(a) Description of Business

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

(b) Partnership Ownership

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

(c) Basis of Presentation

The accompanying consolidated financial statements include the assets, liabilities, and results of operations of the Partnership and its wholly-owned subsidiaries. The Partnership proportionately consolidates its undivided 59.27% interest in a gas processing plant acquired by the Partnership in November 2005 (23.85%) and May 2006 (35.42%). In January 2004, the Partnership adopted FASB ASC 810-10-05-8 and began consolidating its joint venture interest in Crosstex DC Gathering, J.V. (CDC) as discussed more fully in Note 5. The consolidated operations are hereafter referred to herein collectively as the “Partnership.” All material intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements for the prior years to conform to the current presentation.

(2) Significant Accounting Policies

(a) Management’s Use of Estimates

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

(b) Cash and Cash Equivalents

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

(c) Natural Gas and Natural Gas Liquids Inventory

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

(d) Property, Plant, and Equipment

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

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

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

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

Depreciation expense of $76.1 million, $57.0 million and $43.2 million was recorded for the years ended December 31, 2008, 2007 and 2006, respectively.

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

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

The Partnership recorded impairments to long-lived assets of $24.6 million during the year ending December 31, 2008. See Note 3(c) for further details on the long-lived assets impaired. No impairments were incurred during the years ended December 31, 2007 and 2006.

FASB ASC 360-10-05-4 also requires long-lived assets being held for sale or disposed of to be presented in the financial statements separately. During the third quarter of 2008 the Partnership held for sale its undivided 12.4% interest in the Seminole gas processing plant. The sale was finalized on November 17, 2008. All operating results for the Seminole plant are recorded in discontinued operating income and the gain on the disposition of the plant is recorded in gain on sale of discontinued operations. See Note 3(d) for further information on discontinued operations related to the Seminole plant. Details related to other discontinued operations and assets and liabilities held for sale are disclosed in Note 3(d).

(e) Goodwill and Intangibles

The Partnership had approximately $4.9 million of goodwill at December 31, 2007. Goodwill created in the formation of the Partnership of $4.9 million net book value associated with the Midstream assets was impaired during the year ending December 31, 2008. See Note 4 for further details on the impairment of goodwill on the Midstream assets.

Intangible assets consist of customer relationships and the value of the dedicated and non-dedicated acreage attributable to pipeline, gathering and processing systems. The Chief acquisition, as discussed in Note 3(a), included $395.6 million of such intangibles, including the Devon Energy Corporation (Devon) gas gathering agreement. Intangible assets other than the intangibles associated with the Chief acquisition are amortized on a straight-line basis over the expected period of benefits of the customer relationships, which range from three to 15 years. The intangible assets associated with the Chief acquisition are being amortized using the units of throughput method of amortization. The weighted average amortization period for intangible assets is 17.7 years. Amortization of intangibles was approximately $31.4 million, $26.4 million and $13.2 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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

2009	$ 38,334
2010	38,881
2011	43,423
2012	46,199
2013	47,391
Thereafter	357,308
Total	$ 571,536

(f) Other Assets

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

(g) Gas Imbalance Accounting

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

(h) Asset Retirement Obligations

FASB ASC 410-20-25-16 was issued March 2005 which became effective at December 31, 2005. FASB ASC 410-20-25-16 clarifies that the term “conditional asset retirement obligation” as used in FASB ASC 410-20 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Since the obligation to perform the asset retirement activity is unconditional, FASB ASC 410-20-25-16 provides that a liability for the fair value of a conditional asset retirement activity should be recognized if that fair value can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement. FASB ASC 410-20-25-16 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation under FASB ASC 410-20. The Partnership did not provide any asset retirement obligations as of December 31, 2008 or 2007 because it does not have sufficient information as set forth in FASB ASC 410-20-25-16 to reasonably estimate such obligations and the Partnership has no current intention of discontinuing use of any significant assets.

(i) Revenue Recognition

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

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

(j) Derivatives

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

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

(k) Energy Trading Activities

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

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

Net margins earned on settled contracts from the Partnership's energy trading activities included in profit on energy trading activities in the consolidated statement of operations were $3.4 million, $4.1 million and $2.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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

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

(l) Comprehensive Income (Loss)

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

Pursuant to FASB ASC 815, the Partnership records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

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

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

(n) Concentrations of Credit Risk

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

During 2008, 2007 and 2006 Dow Hydrocarbons accounted for 11.0%, 11.8% and 13.4%, respectively, of the consolidated revenue of the Partnership including discontinued operations. As the Partnership continues to grow and expand, the relationship between individual customer sales and consolidated total sales is expected to continue to change. While this customer represents a significant percentage of revenues, the loss of this customer would not have a material adverse impact on the Partnership's results of operations.

(o) Environmental Costs

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

(p) Option Plans

Effective January 1, 2006, the Partnership adopted the provisions of FASB ASC 718 which requires compensation related to all stock-based awards, including stock options, be recognized in the consolidated financial statements.

The Partnership elected to use the modified-prospective transition method for adopting ASC 718. Under the modified-prospective method, awards that are granted, modified, repurchased, or canceled after the date of adoption are measured and accounted for under ASC 718. The unvested portion of awards that were granted prior to the effective date are also accounted for in accordance with ASC 718. Under ASC 718, the Partnership is required to estimate forfeitures in determining periodic compensation cost. The cumulative effect of the adoption of ASC 718 recognized on January 1, 2006 was an increase in net income of $0.7 million due to the reduction in previously recognized compensation costs associated with the estimation of forfeitures.

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

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

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

(q) Financial Statement Recast for Discontinued Operations and Letter of Credit Fees.

The Consolidated Statements of Operations and related earnings per unit have been revised to segregate income related to assets sold in 2009 to discontinued operations and reclassify letter of credit fees from purchased gas expense to interest expense. Discontinued operations as originally reported consisted of the financial activities of the Seminole Gas Processing Plant. During 2009 the Partnership disposed of additional assets and the financial activities of these assets have now been included in discontinued operations in the recast Consolidated Statements of Operations for all periods presented (see Note 3(d)). These assets were held for sale and the final sale concluded during 2009. Additionally, letter of credit fees of $1.5 million, $1.3 million and $0.6 million for the years ended December 31, 2008, 2007, and 2006 respectively, were reclassified from purchased gas expense to interest expense in the Consolidated Statements of Operations to more clearly reflect the cost of financing.

(r) Retrospective Application of Recently Adopted Accounting Standards.

The Partnership has recast its consolidated financial statements as of December 31, 2008, 2007 and 2006 for the adoption of FASB ASC 260-10-45-60 issued June 2008 which requires unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and for the adoption of FASB ASC 810-10-65-1 issued December 2007 which requires non-controlling interests to be treated as a separate component of equity, not as a liability or other item outside of permanent equity.

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

(s) Recent Accounting Pronouncements

As a result of the recent credit crisis, FASB ASC 820-10-35-15A was issued October 2008 and clarifies the application of FASB ASC 820 in a market that is not active and provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. FASB ASC 820-10-35-15A is effective upon issuance, for companies that have adopted FASB ASC 820. The Partnership has evaluated FASB ASC 820-10-35-15A and determined that this standard has no impact on its results of operations, cash flows or financial position for this reporting period.

FASB ASC 260-10-45-60 was issued June 2008 and requires unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents to be treated as *participating securities* as defined in FASB ASC 260-10-20 and, therefore, included in the earnings allocation in computing earnings per share under the two-class method described in FASB ASC 260. FASB ASC 260-10-45-60 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those years. Upon adoption, the Partnership will consider restricted shares with nonforfeitable dividend rights in the calculation of earnings per share and will adjust all prior reporting periods retrospectively to conform to the requirements, although the impact should not be material.

FASB ASC 825-10-05-5 was issued February 2007 and permits entities to choose to measure many financial assets and financial liabilities at fair value. Changes in the fair value on items for which the fair value option has been elected are recognized in earnings each reporting period. FASB ASC 825-10-05-5 also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. FASB ASC 825-10-05-5 was adopted effective January 1, 2008 and did not have a material impact on our financial statements.

FASB ASC 805 and FASB ASC 810-10-65-1 were issued December 2007. FASB ASC 805 requires most identifiable assets, liabilities, noncontrolling interests and goodwill acquired in a business combination to be recorded at "full fair value." The Statement applies to all business combinations, including combinations among mutual entities and combinations by contract alone. Under FASB ASC 805 all business combinations will be accounted for by applying the acquisition method. FASB ASC 805 is effective for periods beginning on or after December 15, 2008. FASB ASC 810-10-65-1 will require noncontrolling interests (previously referred to as minority interests) to be treated as a separate component of equity, not as a liability or other item outside of permanent equity. The statement applies to the accounting for noncontrolling interests and transactions with noncontrolling interest holders in consolidated financial statements. FASB ASC 810-10-65-1 is effective for periods beginning on or after December 15, 2008 and will be applied prospectively to all noncontrolling interests, including any that arose before the effective date, except that comparative period information must be recast to classify noncontrolling interests in equity, attribute net income and other comprehensive income to noncontrolling interests and provide other disclosures required by FASB ASC 810-10-65-1.

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

FASB ASC 815-10-65-1 was issued March 2008 and requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under FASB ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. FASB ASC 815-10-65-1 is effective for fiscal years beginning after November 15, 2008. The principal impact to the Partnership will be to require expanded disclosure regarding derivative instruments.

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

(a) Acquisitions

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

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

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

(b) Dispositions

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

(c) Long-Lived Asset Impairments

Impairments of $24.6 million were recorded in the year ended December 31, 2008 related to long-lived assets. The impairments are comprised of:

- $17.8 million related to the Blue Water gas processing plant located in south Louisiana — The impairment on the Partnership's 59.27% interest in the Blue Water gas processing plant was recognized because the pipeline company which owns the offshore Blue Water system and supplies gas to the Partnership's Blue Water plant reversed the flow of the gas on its pipeline in early January 2009 thereby removing access to all the gas processed at the Blue Water plant from the Blue Water offshore system. At this time, the Partnership has not found an alternative source of new gas for the Blue Water plant so the plant ceased operations in January 2009. An impairment of $17.8 million was recognized for the carrying amount of the plant in excess of the estimated fair value of the plant as of December 31, 2008. The fair value of the Blue Water plant was determined by using the market and cost approach for valuing the plant. The income approach was not considered because the plant is not in operation.
- $4.1 million related to leasehold improvements — The Partnership had planned to relocate its corporate office during 2008 to a larger office facility. The Partnership had leased office space and was close to completing the renovation of this office space when the global economic decline began impacting its operations in October 2008. On December 31, 2008, the decision was made to cancel the new office lease and not relocate the corporate offices from its existing office location. The impairment relates to the leasehold improvements on the office space for the cancelled lease.
- $2.6 million related to the Arkoma gathering system — The impairment on the Arkoma gathering system was recognized because the Partnership sold this asset in February 2009 for approximately $11.0 million and the carrying amount of the asset exceeded the sale price by approximately $2.6 million.

(d) Discontinued Operations

As part of the Partnership's strategy to increase liquidity in response to the tightening financial markets, the Partnership began marketing a non-strategic asset for sale in late September 2008. In early October 2008, the Partnership entered into an agreement to sell its undivided 12.4% interest in the Seminole gas processing plant to a third party for $85.0 million. The transaction was completed on November 17, 2008. This asset was previously presented in the Partnership's Treating segment. The consolidated balance sheets at December 31, 2008 and 2007 do not reflect the asset held for sale due to the fact that the decision to dispose of the asset occurred after December 31, 2007, and the sale was completed prior to December 31, 2008.

During 2009, the Partnership sold certain non-strategic assets and used the proceeds from such sales to reduce long-term indebtedness.

The Partnership sold its Midstream assets in Alabama, Mississippi and south Texas for net proceeds of $218.4 million (after final purchase price adjustments) in August 2009. Sales proceeds, net of transaction costs and other obligations associated with the sale, of $212.0 million were used to repay long-term indebtedness and the Partnership recognized a gain on sale of $97.2 million. On October 1, 2009, the Partnership sold its Treating assets for net proceeds of $265.4 million (after final purchase price adjustments). Sales proceeds, net of transaction costs and other obligations associated with the sale, of $258.1 million were used to repay long-term indebtedness and the Partnership recognized a gain on sale of $86.3 million.

The revenues, operating expenses, general and administrative expenses associated directly with the sold assets, depreciation and amortization expense, allocated Texas margin tax and an allocated interest expense related to the operations of the sold assets have been segregated from continuing operations and reported as discontinued operations for all periods. No corporate office general and administrative expenses have been allocated to income from discontinued operations. Following are revenues and income from discontinued operations (in thousands):

	Years Ended December 31,		
	2008	2007	2006
Midstream revenues	$ 1,766,101	$ 1,411,092	$ 1,540,681
Treating revenues(1)	$ 73,492	$ 65,025	$ 63,813
Net income from discontinued operations, net of tax(1)	$ 74,812	$ 31,343	$ 20,714

(1) Values include the Seminole processing plant sold in November 2008. The net income from discontinued operations includes a $1.0 million impairment loss on Treating inventory write down.

(4) Goodwill Impairment

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

(5) Investment in Limited Partnerships and Note Receivable

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

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

(6) Long-Term Debt

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- bankruptcy or other insolvency events;
- a change in control (as defined in the credit agreement); and
- the failure of any representation or warranty to be materially true and correct when made.

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

The Partnership is subject to interest rate risk on its credit facility and has entered into interest rate swaps to reduce this risk. See Note 13 to the financial statements for a discussion of interest rate swaps.

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

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

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

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

On November 7, 2008, the Partnership amended our senior secured note agreement governing its senior secured notes to, among other things, (i) modify the maximum permitted leverage ratio and lower the minimum interest coverage ratio it must maintain consistent with the ratios under the Fifth Amendment to the bank credit facility, (ii) permit it to sell certain assets and (iii) increase the interest rate it pays on the senior secured notes. The interest rate the Partnership paid on the senior secured notes increased by 1.25% for the fourth quarter of 2008 due to this amendment.

The covenants and terms of default for the senior secured notes are substantially the same as the covenants and default terms under the Partnership's bank credit facility, and therefore the agreements governing the senior secured notes also required amendment in 2009. On February 27, 2009, the Partnership amended its senior note agreements to (i) increase the maximum permitted leverage ratio and to lower the minimum interest coverage ratio it must maintain consistent with the ratios under the Sixth Amendment to the bank credit facility, (ii) revise the mandatory prepayment terms consistent with the terms under the Sixth Amendment to the bank credit facility, (iii) increase the interest rate it pays on the senior secured notes and (iv) provide for the payment of a leverage fee consistent with the terms of bank credit facility. Commencing February 27, 2009 the interest rate the Partnership pays in cash on all of the senior secured notes will increase by 2.25% per annum for each of the fiscal quarters commencing with the quarter ending March 31, 2009 over the comparative interest rates under the senior note agreements prior to the November and February amendments. As a result of this rate increase, the weighted average interest rate on the outstanding balance on the senior secured notes is approximately 9.25% as of February 2009.

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

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

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

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

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

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

The Partnership was in compliance with all debt covenants at December 31, 2008 and 2007 and expects to be in compliance with debt covenants for the next twelve months.

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

Maturities. Maturities for the long-term debt as of December 31, 2008 are as follows (in thousands):

2009	$ 9,412
2010	20,294
2011	816,000
2012	93,000
2013	93,000
Thereafter	232,000

(7) Other Long-Term Liabilities

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

	Years Ended December 31,	
	2008	2007
Compressor equipment	$ 28,890	$ 4,011
Less: Accumulated amortization	(1,523)	(29)
Net assets under capital lease	$ 27,367	$ 3,982

The following are the minimum lease payments to be made in each of the following years indicated for the capital lease in effect as of December 31, 2008 (in thousands):

Fiscal Year	
2009 through 2013	$ 16,150
Thereafter	16,691
Less: Interest	(5,184)
Net minimum lease payments under capital lease	27,657
Less: Current portion of net minimum lease payments	(3,189)
Long-term portion of net minimum lease payments	$ 24,468

(8) Income Taxes

The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The net tax basis in the Partnership's assets and liabilities is less than the reported amounts on the financial statements by approximately $437.2 million as of December 31, 2008. Effective January 1, 2007, the Partnership is subject to the margin tax enacted by the state of Texas on May 1, 2006.

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

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

	2008	2007	2006
Current tax provision (benefit)	$ 2,197	$ 507	$ (268)
Deferred tax provision	172	253	490
Income tax provision on continuing operations	2,369	760	222
Income tax provision on discontinued operations	396	204	—
Tax provision	$ 2,765	$ 964	$ 222

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

Federal income tax on taxable corporation at statutory rate (35)%	$ 197	$ 206	$ 206
State income taxes, net	2,568	758	16
Income tax provision	$ 2,765	$ 964	$ 222

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

	Years Ended December 31, 2008	2007
Deferred income tax assets:		
Net operating loss carryforward — current	$ 41	$ 4
Net operating loss carryforward — long-term	—	61
Alternative minimum tax credit carryover — long-term	—	99
	$ 41	$ 164
Deferred income tax liabilities:		
Property, plant, equipment, and intangible assets-current	$ (501)	$ (501)
Property, plant, equipment and intangible assets-long-term	(8,727)	(8,678)
	$ (9,228)	$ (9,179)
Net deferred tax liability	$ (9,187)	$ (9,015)

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

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

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

Unrecognized tax benefits of $1.6 million, if recognized, would affect the effective tax rate. We do not expect any material change in the balance of our unrecognized tax benefits over the next twelve months. In the event interest or penalties are incurred with respect to income tax matters, our policy will be to include such items in income tax expense. At December 31, 2008, tax years 2005 through 2008 remain subject to examination by the Internal Revenue Service and applicable states.

(9) Partners' Capital

(a) Issuance of Common Units

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

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

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

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

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

(c) Senior Subordinated Series D Units

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

(d) Cash Distributions

Unless restricted by the terms of our credit facility, the Partnership must make distributions of 100% of available cash, as defined in the partnership agreement, within 45 days following the end of each quarter commencing with the quarter ended on March 31, 2003. Distributions will generally be made 98% to the common and subordinated unitholders and 2% to the general partner, subject to the payment of incentive distributions.

Under the quarterly incentive distribution provisions, generally our general partner is entitled to 13% of amounts we distribute in excess of $0.25 per unit, 23% of the amounts we distribute in excess of $0.3125 per unit and 48% of amounts we distribute in excess of $0.375 per unit. Incentive distributions totaling $30.8 million, $24.8 million and $20.4 million were earned by our general partner for the years ended December 31, 2008, 2007 and 2006, respectively. The Partnership paid annual per common unit distributions of $2.36, $2.28 and $2.13 for the years ended December 31, 2008, 2007 and 2006, respectively.

The Partnership decreased its fourth quarter distribution on its common units to $0.25 per unit which was paid February 13, 2009.

See Note 6 for a description of the Partnership's credit facilities which restrict the Partnership's ability to make future distributions.

(e) Earnings per unit and anti-dilutive computations

The Partnership's common units and subordinated units participate in earnings and distributions in the same manner for all historical periods and are therefore presented as a single class of common units for earnings per unit computations. The various series of senior subordinated units are also considered common securities, but because they do not participate in earnings or cash distributions during the subordination period are presented as separate classes of common equity. Each of the series of senior subordinated units were issued at a discount to the market price of the common units they are convertible into at the end of the subordination period. These discounts represent beneficial conversion features (BCFs) under FASB ASC 470-20-25-4. Under FASB ASC 470-20-25-4 and related accounting guidance, a BCF represents a non-cash distribution that is treated in the same way as a cash distribution for earnings per unit computations. Since the conversion of all the series of senior subordinated units into common units are contingent (as described with the terms of such units) until the end of the subordination periods for each series of units, the BCF associated with each series of senior subordinated units is not reflected in earnings per unit until the end of such subordination periods when the criteria for conversion are met. Following is a summary of the BCFs attributable to the senior subordinated units outstanding during 2006, 2007 and 2008 (in thousands):

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

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

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

	Years Ended December 31,		
	2008	2007	2006
Limited partners' interest in net income (loss)	$ (15,644)	$ (5,363)	$ (20,647)
Distributed earnings allocated to:			
Common units(1)	$ 95,961	$ 60,851	$ 55,827
Unvested restricted units	1,290	909	—
Senior subordinated A units(2)	—	—	7,941
Senior subordinated series C units(2)	121,112	—	—
Total distributed earnings	$ 218,363	$ 61,760	$ 63,768
Undistributed loss allocated to:			
Common units(3)	$ (230,903)	$ (66,068)	$ (84,415)
Unvested restricted units	(3,104)	(1,055)	—
Senior subordinated A units	—	—	—
Senior subordinated series C units	—	—	—
Total undistributed loss	$ (234,007)	$ (67,123)	$ (84,415)
Net income (loss) allocated to:			
Common units	$ (134,941)	$ (5,217)	$ (28,588)
Unvested restricted units	(1,815)	(146)	—
Senior subordinated A units	—	—	7,941
Senior subordinated series C units	121,112	—	—
Total limited partners' interest in net income (loss)	$ (15,644)	$ (5,363)	$ (20,647)
Limited Partner's interest in income from discontinued operations:			
Common units(4)	$ 72,420	$ 30,234	$ 20,300
Unvested restricted units	896	482	—
Senior subordinated series A, C and D units	—	—	—
Total income from discontinued operations	$ 73,316	$ 30,716	$ 20,300
Cumulative effect of the change in accounting principle:			
Common units	$ —	$ —	$ 689
Unvested restricted units	—	—	—
Senior subordinated A, C and D units	—	—	—
Total cumulative effect of the change in accounting principle	$ —	$ —	$ 689
Basic and diluted net loss per unit from continuing operations:			
Basic and diluted common units	$ (4.90)	$ (1.33)	$ (1.86)
Senior subordinated A units	$ —	$ —	$ 5.31
Senior subordinated series C units	$ 9.44	$ —	$ —
Senior subordinated series D units	$ —	$ —	$ —
Basic and diluted net income on discontinued operations:			
Basic and diluted common units	$ 1.71	$ 1.13	$ 0.77
Senior subordinated A, C and D units	$ —	$ —	$ —
Basic cumulative effect of change in accounting principle per unit:			
Common units	$ —	$ —	$ 0.03
Senior subordinated A, C and D units	$ —	$ —	$ —
Total basic and diluted net income (loss) per unit:			
Basic and diluted common units	$ (3.19)	$ (0.20)	$ (1.09)
Senior subordinated A units	$ —	$ —	$ 5.31
Senior subordinated series C units	$ 9.44	$ —	$ —
Senior subordinated series D units	$ —	$ —	$ —

footnotes on following page

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

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

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

(4) Represents 98.0% for the limited partners' interest in discontinued operations.

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

	Years Ended December 31,		
	2008	2007	2006
Weighted average limited partner common units outstanding	42,330	26,753	26,337
Weighted average senior subordinated A units	—	—	1,495
Weighted average senior subordinated series C units	12,830	—	—

All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented. All common unit equivalents were antidilutive for the years ended December 31, 2008, 2007 and 2006 because the limited partners were allocated net losses in the periods.

Net income is allocated to the general partner in an amount equal to its incentive distributions as described in Note 9(d). In June 2005, the Partnership amended its partnership agreement to allocate the expenses attributable to CEI stock options and restricted stock all to the general partner to match the related general partner contribution. Therefore, the general partner's share of net income is reduced by stock-based compensation expense attributed to CEI stock options and restricted stock. The remaining net income after incentive distributions and CEI-related stock-based compensation is allocated pro rata between the 2% general partner interest, the subordinated units and the common units. The net income allocated to the general partner is as follows (in thousands):

	Years Ended December 31,		
	2008	2007	2006
Income allocation for incentive distributions	$ 30,772	$ 24,802	$ 20,422
Stock-based compensation attributable to CEI's stock options and restricted shares	(4,665)	(5,441)	(3,545)
2% general partner interest in net income (loss)	308	(109)	(421)
General partner share of net income	$ 26,415	$ 19,252	$ 16,456

(10) Retirement Plans

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

(11) Employee Incentive Plans

(a) Long-Term Incentive Plan

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

(b) Restricted Units

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

The restricted units are intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive and the Partnership will receive no remuneration for the units. The restricted units include a tandem award that entitles the participant to receive cash payments equal to the cash distributions made by the Partnership with respect to its outstanding common units until the restriction period is terminated or the restricted units are forfeited. The restricted units granted in 2006, 2007 and 2008 generally cliff vest after three years of service.

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the year ended December 31, 2008 is provided below:

Crosstex Energy, L.P. Restricted Units:	Number of Units	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	504,518	$ 34.29
Granted	432,354	29.60
Vested*	(204,033)	33.40
Forfeited	(34,273)	29.69
Reduced estimated performance units	(154,499)	31.66
Non-vested, end of period	544,067	$ 31.90
Aggregate intrinsic value, end of period (in thousands)	$ 2,378	

* Vested units include 51,214 units withheld for payroll taxes paid on behalf of employees.

The Partnership's executive officers were granted restricted units during 2008 and 2007, the number of which may increase or decrease based on the accomplishment of certain performance targets based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over a three-year period). The minimum number of restricted units for all executives of 52,795 and 14,319 for 2008 and 2007, respectively, are included in the non-vested end of period units line in the table above. Target performance grants were previously included in the restricted units granted and were included in share-based compensation as it appeared probable that target thresholds would be achieved. However, during the last half of 2008, the Partnership's assets were negatively impacted by hurricanes Gustav and Ike. During this same period, the Partnership has also been negatively impacted by the declines in natural gas and NGL prices coupled with the global economic decline and tightening of capital markets. The impact of these events was significant enough to make the achievement of target performance goals less than probable. Therefore, an expense of $0.7 million previously recorded for target performance-based restricted units has been reversed and is shown as a reduction to stock-based compensation expense and a reduction in the number of estimated performance units outstanding of 154,499 units in the year ended December 31, 2008. All performance-based awards greater than the minimum performance grant levels will be subject to reevaluation and adjustment until the restricted units vest. The performance-based restricted units are included in the current share-based compensation calculations as required by FASB ASC 718 when it is deemed probable of achieving the performance criteria.

A summary of the restricted units aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2008 and 2007 are provided below (in thousands):

	Years Ended December 31,	
Crosstex Energy, L.P. Restricted Units:	**2008**	**2007**
Aggregate intrinsic value of units vested	$5,907	$1,342
Fair value of units vested	$6,815	$ 888

As of December 31, 2008, there was $7.8 million of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.5 years.

(c) Unit Options

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

The fair value of each unit option award is estimated at the date of grant using the Black-Scholes-Merton model. This model is based on the assumptions summarized below. Expected volatilities are based on historical volatilities of the Partnership's traded common units. The Partnership has used historical data to estimate share option exercise and employee departure behavior to estimate expected forfeiture rates. The expected life of unit options represents the period of time that unit options granted are expected to be outstanding. The risk-free interest rate for periods within the expected term of the unit option is based on the U.S. Treasury yield curve in effect at the time of the grant. The Partnership used the simplified method to calculate the expected term.

Unit options are generally awarded with an exercise price equal to the market price of the Partnership's common units at the date of grant. The unit options granted in 2008, 2007 and 2006 generally vest based on 3 years of service (one-third after each year of service). The following weighted average assumptions were used for the Black-Scholes option-pricing model for grants in 2008, 2007 and 2006:

	Years Ended December 31,		
Crosstex Energy, L.P. Unit Options Granted:	**2008**	**2007**	**2006**
Weighted average distribution yield	7.15%	5.75%	5.5%
Weighted average expected volatility	30.0%	32.0%	33.0%
Weighted average risk free interest rate	1.81%	4.39%	4.80%
Weighted average expected life	6 years	6 years	6 years
Weighted average contractual life	10 years	10 years	10 years
Weighted average of fair value of unit options granted	$3.48	$6.73	$7.45

A summary of the unit option activity for the years ended December 31, 2008, 2007 and 2006 is provided below:

	Years Ended December 31,					
	2008		2007		2006	
	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	1,107,309	$ 29.65	926,156	$ 25.70	1,039,832	$ 18.88
Granted(b)	402,185	31.58	347,599	37.29	286,403	34.62
Exercised	(56,678)	14.16	(90,032)	18.20	(304,936)	11.19
Forfeited	(90,208)	31.29	(67,688)	29.84	(95,143)	24.56
Expired	(58,414)	32.93	(8,726)	31.60	—	—
Outstanding, end of period	1,304,194	$ 30.64	1,107,309	$ 29.65	926,156	$ 25.70
Options exercisable at end of period	540,782	$ 29.12	281,973	$ 28.05	121,131	$ 23.58
Weighted average contractual term (years) end of period:						
Options outstanding	7.4	—	7.6	—	7.8	—
Options exercisable	6.5	—	7.1	—	7.5	—
Aggregate intrinsic value end of period (in thousands):						
Options outstanding	$ (a)	—	$ 4,681	—	$ 13,107	—
Options exercisable	$ (a)	—	$ 1,322	—	$ 1,970	—

(a) Exercise price on all outstanding options exceed current market price.

(b) No options were granted with an exercise price less than or equal to market value at grant during 2008, 2007 and 2006.

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

	Years Ended December 31,	
Crosstex Energy, L.P. Unit Options:	2008	2007
Intrinsic value of units options exercised	$746	$1,675
Fair value of units vested	$279	$ 197

As of December 31, 2008, there was $1.6 million of unrecognized compensation cost related to non-vested unit options. That cost is expected to be recognized over a weighted-average period of 1.5 years.

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

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

CEI's restricted shares are included at their fair value at the date of grant which is equal to the market value of the common stock on such date. CEI's restricted stock granted in 2006, 2007 and 2008 generally cliff vest after three years of service. A summary of the restricted stock activity which includes officers and employees of the Partnership and directors of CEI for the year ended December 31, 2008, is provided below:

Crosstex Energy, Inc. Restricted Shares:	Number of Shares	Weighted Average Grant-Date Fair Value
Non-vested, beginning of period	860,275	$ 21.16
Granted	361,796	32.62
Vested*	(401,004)	18.41
Forfeited	(63,716)	21.86
Reduced estimated performance shares	(153,038)	32.10
Non-vested, end of period	604,313	$ 27.62
Aggregate intrinsic value, end of period (in thousands)	$ 2,357	

* Vested shares include 116,118 shares withheld for payroll taxes paid on behalf of employees.

The Partnership's executive officers were granted restricted shares during 2008 and 2007, the number of which may increase or decrease based on the accomplishment of certain performance targets based on the Partnership's average growth rate (defined as the percentage increase or decrease in distributable cash flow per common unit over a three-year period). The minimum number of restricted shares for all executives of 50,090 and 16,536 for 2008 and 2007, respectively, are included in the non-vested, end of period shares line in the table above. Target performance grants were previously included in the restricted units granted and were included in share-based compensation as it appeared probable that target thresholds would be achieved. However, during the last half of 2008, the Partnership's assets were negatively impacted by hurricanes Gustav and Ike. During this same period, the Partnership has also been negatively impacted by the declines in natural gas and NGL prices coupled with the global economic decline and tightening of capital markets. The impact of these events was significant enough to make the achievement of target performance goals less than probable. Therefore, an expense of $0.7 million previously recorded for target performance-based restricted shares has been retroactively reversed and is shown as a reduction to stock-based compensation expense and a reduction in the number of estimated performance shares outstanding by 153,038 shares in the year ended December 31, 2008. All performance-based awards greater than the minimum performance grant levels will be subject to reevaluation and adjustment until the restricted shares vest. The performance-based restricted shares are included in the current share-based compensation calculations as required by FASB ASC 718 when it is deemed probable of achieving the performance criteria.

A summary of the restricted shares' aggregate intrinsic value (market value at vesting date) and fair value of shares vested (market value at date of grant) during the years ended December 31, 2008 and 2007 are provided below (in thousands):

Crosstex Energy, Inc. Restricted Shares:	Years Ended December 31, 2008	2007
Aggregate intrinsic value of shares vested	$13,493	$3,067
Fair value of shares vested	$ 7,382	$1,275

Restricted shares in CEI totaling 244,578 and 186,840 were issued to officers and employees of the Partnership with a weighted-average grant-date fair value of $29.58 and $25.05 per share in 2007 and 2006, respectively. As of December 31, 2008 and 2007, there was $7.2 million and $7.0 million, respectively, of unrecognized compensation costs related to CEI restricted shares for officers and employees. The cost is expected to be recognized over a weighted average period of 2.4 years.

CEI Stock Options

No CEI stock options were granted to any officers or employees of the Partnership during 2008, 2007 and 2006.

A summary of the stock option activity includes officers and employees of the Partnership and directors of CEI for the years ended December 31, 2008, 2007 and 2006 is provided below:

	Years Ended December 31,					
	2008		2007		2006	
	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price	Number of Shares(a)	Weighted Average Exercise Price(a)
Outstanding, beginning of period	105,000	$ 8.45	120,000	$ 8.21	159,933	$ 9.53
Granted	—	—	—	—	—	—
Cancelled	—	—	—	—	—	—
Exercised	(37,500)	6.50	(15,000)	6.50	(9,933)	12.58
Forfeited	—	—	—	—	(30,000)	13.83
Outstanding, end of period	67,500	$ 9.54	105,000	$ 8.45	120,000	$ 8.21
Options exercisable at end of period	22,500	$ 11.05	37,500	$ 7.87	—	—

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

The following is a summary of the CEI stock options outstanding attributable to officers and employees of the Partnership as of December 31, 2008:

Outstanding stock options (15,000 exercisable) (post stock split)	30,000
Weighted average exercise price (post stock split)	$ 13.33
Aggregate intrinsic value	$ —
Weighted average remaining contractual term	5.9 years

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

	Years Ended December 31,	
Crosstex Energy, Inc. Stock Options:	2008	2007
Intrinsic value of units options exercised	$1,089	$366
Fair value of units vested	$ 38	$ 66

No stock options were granted, cancelled, exercised or forfeited by officers and employees of the Partnership during the years ended December 31, 2008, 2007 and 2006.

As of December 31, 2008, there was $15,449 of unrecognized compensation costs related to non-vested CEI stock options. The cost is expected to be recognized over a weighted average period of 0.8 years.

(12) Fair Value of Financial Instruments

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

	December 31, 2008		December 31, 2007	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 1,636	$ 1,636	$ 142	$ 142
Trade accounts receivable and accrued revenues	341,853	341,853	489,889	489,889
Fair value of derivative assets	31,794	31,794	9,926	9,926
Note receivable	375	375	1,026	1,026
Accounts payable, drafts payable and accrued gas purchases	315,622	315,622	469,951	469,951
Current portion of long-term debt	9,412	9,412	9,412	9,412
Long-term debt	1,254,294	1,148,939	1,213,706	1,225,087
Fair value of derivative liabilities	51,281	51,281	30,492	30,492

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

The Partnership's long-term debt was comprised of borrowings under a revolving credit facility totaling $784.0 million and $734.0 million as of December 31, 2008 and 2007, respectively, which accrues interest under a floating interest rate structure. Accordingly, the carrying value of such indebtedness approximates fair value for the amounts outstanding under the credit facility. As of December 31, 2008, the Partnership also had borrowings totaling $479.7 million under senior secured notes with a weighted average interest rate of 8.0%. The fair value of these borrowings as of December 31, 2008 and 2007 were adjusted to reflect current market interest rate for such borrowings as of December 31, 2008 and 2007, respectively.

The fair value of derivative contracts included in assets or liabilities for risk management activities represents the amount at which the instruments could be exchanged in a current arms-length transaction.

(13) Derivatives

Interest Rate Swaps

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

The Partnership entered into eight interest rate swaps prior to September 2008 as shown below:

Trade Date	Term	From	To	Rate	Notional Amounts (In thousands)
November 14, 2006	4 years	November 28, 2006	November 30, 2010	4.3800%	$ 50,000
March 13, 2007	4 years	March 30, 2007	March 31, 2011	4.3950%	50,000
July 30, 2007	4 years	August 30, 2007	August 30, 2011	4.6850%	100,000
August 6, 2007	4 years	August 30, 2007	August 31, 2011	4.6150%	50,000
August 9, 2007	3 years	November 30, 2007	November 30, 2010	4.4350%	50,000
August 16, 2007*	4 years	October 31, 2007	October 31, 2011	4.4875%	100,000
September 5, 2007	4 years	September 28, 2007	September 28, 2011	4.4900%	50,000
January 22, 2008	1 year	January 31, 2008	January 31, 2009	2.8300%	100,000
					$ 550,000

* Amended swap is a combination of two swaps that each had a notional amount of $50.0 million with the same original term.

Each swap fixes the three month LIBOR rate, prior to credit margin, at the indicated rates for the specified amounts of related debt outstanding over the term of each swap agreement. In January 2008, the Partnership amended existing swaps with the counterparties in order to reduce the fixed rates and extend the terms of the existing swaps by one year. The Partnership also entered into one new swap in January 2008.

The Partnership had previously elected to designate all interest rate swaps (except the November 2006 swap) as cash flow hedges for FASB ASC 815 accounting treatment. Accordingly, unrealized gains and losses relating to the designated interest rate swaps were recorded in accumulated other comprehensive income. Immediately prior to the January 2008 amendments, these swaps were de-designated as cash flow hedges. The unrealized loss in accumulated other comprehensive income of $17.0 million at the de-designation dates is being reclassified to earnings over the remaining original terms of the swaps using the effective interest method. The related loss reclassified to earnings and included in (gain) loss on derivatives during the year ended December 31, 2008 is $6.4 million.

The Partnership elected not to designate any of the amended swaps or the new swap entered into in January 2008 as cash flow hedges for FASB ASC 815 treatment. Accordingly, unrealized gains and losses are recorded through the consolidated statement of operations in (gain) loss on derivatives over the period hedged.

In September 2008, the Partnership entered into four additional interest rate swaps. The effect of the new interest rate swaps was to convert the floating rate portion of the original swaps on $450.0 million (all swaps except the January 22, 2008 swap that expires January 31, 2009) from three month LIBOR to one month LIBOR. The Partnership received a cash settlement in September of $1.4 million which represented the present value of the basis point differential between one month LIBOR and three month LIBOR. The $1.4 million was recorded in the consolidated statement of operations in (gain) loss on derivatives.

The table below aligns the new swap which receives one month LIBOR and pays three month LIBOR with the original interest rate swaps.

Original Swap Trade Date	New Trade Date	From	To	Notional Amounts (In thousands)
March 13, 2007	September 12, 2008	September 30, 2008	March 31, 2011	$ 50,000
September 5, 2007	September 12, 2008	September 30, 2008	September 28, 2011	50,000
August 16, 2007	September 12, 2008	October 30, 2008	October 31, 2011	100,000
November 14, 2006	September 12, 2008	November 28, 2008	November 30, 2010	50,000
August 9, 2007	September 12, 2008	November 28, 2008	November 30, 2010	50,000
July 30, 2007	September 12, 2008	November 28, 2008	August 30, 2011	100,000
August 6, 2007	September 23, 2008	November 28, 2008	August 30, 2011	50,000
				$ 450,000

The impact of the interest rate swaps on net income is included in other income (expense) in the consolidated statements of operations as a part of interest expense, net, as follows (in thousands):

	Years Ended December 31, 2008	2007
Change in fair value of derivatives that do not qualify for hedge accounting	$ (22,105)	$ (1,185)
Realized gains on derivatives	(4,608)	707
Ineffective portion of derivatives qualifying for hedge accounting	—	—
	$ (26,713)	$ (478)

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

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

	Years Ended December 31, 2008	2007
Fair value of derivative assets — current	$ 149	$ 68
Fair value of derivative assets — long-term	—	—
Fair value of derivative liabilities — current	(17,217)	(3,266)
Fair value of derivative liabilities — long-term	(18,391)	(8,057)
Net fair value of interest rate swaps	$ (35,459)	$ (11,255)

Commodity Swaps

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

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

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

	Years Ended December 31,		
	2008	2007	2006
Change in fair value of derivatives that do not qualify for hedge accounting	$ (246)	$ 1,197	$ 713
Realized (gains) losses on derivatives	(13,352)	(7,918)	(2,238)
Ineffective portion of derivatives qualifying for hedge accounting	(72)	104	(74)
Net gains related to commodity swaps	$ (13,670)	$ (6,617)	$ (1,599)
Adjusted for net gains (losses) included in income from discontinued operations	5,051	2,470	1,425
Gain on derivatives included in continuing operations	$ (8,619)	$ (4,147)	$ (174)

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

	Years Ended December 31,	
	2008	2007
Fair value of derivative assets — current	$ 27,017	$ 8,521
Fair value of derivative assets — long term	4,628	1,337
Fair value of derivative liabilities — current	(11,289)	(17,800)
Fair value of derivative liabilities — long term	(4,384)	(1,369)
Net fair value of commodity swaps	$ 15,972	$ (9,311)

Set forth below is the summarized notional volumes and fair values of all instruments held for price risk management purposes and related physical offsets at December 31, 2008 (all gas volumes are expressed in MMBtu's and liquids are expressed in gallons). The remaining terms of the contracts extend no later than June 2010 for derivatives, except for certain basis swaps that extend to March 2012. The Partnership's counterparties to derivative contracts include BP Corporation, Total Gas & Power, Fortis, Morgan Stanley, J. Aron & Co., a subsidiary of Goldman Sachs and Sempra Energy. Changes in the fair value of the Partnership's mark to market derivatives are recorded in earnings in the period the transaction is entered into. The effective portion of changes in the fair value of cash flow hedges is recorded in accumulated other comprehensive income until the related anticipated future cash flow is recognized in earnings. The ineffective portion is recorded in earnings immediately.

Transaction Type	December 31, 2008 Volume	Fair Value
	(In thousands)	
Cash Flow Hedges:		
Natural gas swaps (short contracts) (MMBtu's)	(600)	$ 1,136
Liquids swaps (short contracts) (gallons)	(16,026)	12,578
Total swaps designated as cash flow hedges		$ 13,714
*Mark to Market Derivatives:**		
Swing swaps (long contracts)	2,155	$ 10
Physical offsets to swing swap transactions (short contracts)	(2,155)	—
Swing swaps (short contracts)	(397)	(3)
Physical offsets to swing swap transactions (long contracts)	397	—
Basis swaps (long contracts)	82,681	7,464
Physical offsets to basis swap transactions (short contracts)	(1,550)	9,072
Basis swaps (short contracts)	(78,025)	(6,175)
Physical offsets to basis swap transactions (long contracts)	1,771	(9,067)
Third-party on-system financial swaps (long contracts)	2,300	(8,065)
Physical offsets to third-party on-system transactions (short contracts)	(2,283)	8,157
Third-party on-system financial swaps (short contracts)	(172)	2
Physical offsets to third-party on-system transactions (long contracts)	155	89
Storage swap transactions (long contracts)	158	(23)
Storage swap transactions (short contracts)	(353)	797
Total mark to market derivatives		$ 2,258

* All are gas contracts, volume in MMBtu's

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

Impact of Cash Flow Hedges

The impact of realized gains or losses from derivatives designated as cash flow hedge contracts in the consolidated statements of operations is summarized below (in thousands):

Increase (Decrease) in Midstream Revenue	Years Ended December 31, 2008	2007	2006
Natural gas	$ 63	$ 5,533	$ 5,886
Liquids	(10,402)	(4,066)	1,504
Adjusted for realized (gain) loss included in income from discontinued operations	3,127	(474)	(1,680)
	$ (7,212)	$ 993	$ 5,710

Natural Gas

As of December 31, 2008 an unrealized derivative fair value net gain of $0.8 million related to cash flow hedges of gas price risk was recorded in accumulated other comprehensive income (loss). Of this net amount, a $0.8 million gain is expected to be reclassified into earnings through December 2009. The actual reclassification to earnings will be based on mark to market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

The settlement of cash flow hedge contracts related to January 2009 gas production increased gas revenue by approximately $0.1 million.

Liquids

As of December 31, 2008, an unrealized derivative fair value net gain of $12.0 million related to cash flow hedges of liquids price risk was recorded in accumulated other comprehensive income (loss). Of this amount, a $12.0 million gain is expected to be reclassified into earnings through December 2009. The actual reclassification to earnings will be based on mark to market prices at the contract settlement date, along with the realization of the gain or loss on the related physical volume, which amount is not reflected above.

Derivatives Other Than Cash Flow Hedges

Assets and liabilities related to third party derivative contracts, swing swaps, basis swaps, storage swaps and processing margin swaps are included in the fair value of derivative assets and liabilities and the profit and loss on the mark to market value of these contracts are recorded net as (gain) loss on derivatives in the consolidated statement of operations. The Partnership estimates the fair value of all of its energy trading contracts using actively quoted prices. The estimated fair value of energy trading contracts by maturity date was as follows (in thousands):

	Maturity Periods: Less Than One Year	One to Two Years	More Than Two Years	Total Fair Value
December 31, 2008	$ 2,014	$ 181	$ 63	$ 2,258

(14) Fair Value Measurements

FASB ASC 820 was issued September 2006 and introduces a framework for measuring fair value and expands required disclosure about fair value measurements of assets and liabilities. FASB ASC 820 for financial assets and liabilities is effective for fiscal years beginning after November 15, 2007. The Partnership has adopted the standard for those assets and liabilities as of January 1, 2008 and the impact of adoption was not significant.

Fair value is defined as the price at which an asset could be exchanged in a current transaction between knowledgeable, willing parties. A liability's fair value is defined as the amount that would be paid to transfer the liability to a new obligor, not the amount that would be paid to settle the liability with the creditor. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, use of unobservable prices or inputs are used to estimate the current fair value, often using an internal valuation model. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the item being valued.

FASB ASC 820 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The Partnership's derivative contracts primarily consist of commodity swaps and interest rate swap contracts which are not traded on a public exchange. The fair values of commodity swap contracts are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. The Partnership determines the value of interest rate swap contracts by utilizing inputs and quotes from the counterparties to these contracts. The reasonableness of these inputs and quotes is verified by comparing similar inputs and quotes from other counterparties as of each date for which financial statements are prepared.

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in thousands):

	Total	Level 1	Level 2	Level 3
Interest rate swaps*	$ (35,459)	—	$ (35,459)	—
Commodity swaps*	15,972	—	15,972	—
Total	$ (19,487)	—	$ (19,487)	—

* Unrealized gains or losses on commodity derivatives qualifying for hedge accounting are recorded in accumulated other comprehensive income (loss) at each measurement date. Accumulated other comprehensive income also includes the unrealized losses on interest rate swaps of $17.0 million recorded prior to de-designation in January 2008, of which $6.4 million has been amortized to earnings through December 2008.

(15) Transactions with Related Parties

(a) Plants Transferred from Crosstex Energy Inc.

During 2008 CEI transferred two inactive processing plants to the Partnership at net book value for a cash price of $0.4 million which represented the fair value of the plants.

(b) General and Administrative Expenses

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

(16) Commitments and Contingencies

(a) Leases — Lessee

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

The following table summarizes the Partnership's remaining non-cancelable future payments under operating leases with initial or remaining non-cancelable lease terms in excess of one year (in thousands):

2009	$ 27,197
2010	18,494
2011	17,686
2012	16,327
2013	3,099
Thereafter	3,705
	$ 86,508

Operating lease rental expense in the years ended December 31, 2008, 2007 and 2006, was approximately $39.4 million, $27.9 million, and $20.7 million, respectively.

(b) Employment Agreements

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

(c) Environmental Issues

The Partnership acquired the south Louisiana processing assets from the El Paso Corporation in November 2005. One of the acquired locations, the Cow Island Gas Processing Facility, has an active remediation project for benzene contaminated groundwater. The cause of contamination was attributed to a leaking natural gas condensate storage tank. The site investigation and active remediation being conducted at this location is under the oversight of the Louisiana Department of Environmental Quality (LDEQ) and is being conducted under the Risk-Evaluation and Corrective Action Plan Program (RECAP) rules. In addition, the Partnership is working with both the LDEQ and the Louisiana State University, Louisiana Water Resources Research Institute, on the development and implementation of a new remediation technology that is expected to significantly reduce the cost of and timing for remediation projects. As of December 31, 2008, we had incurred approximately $0.5 million in remediation costs. Since this remediation project is a result of previous owners' operation and the actual contamination occurred prior to our ownership, these costs were accrued as part of the purchase price.

The Partnership acquired LIG Pipeline Company and its subsidiaries on April 1, 2004. Contamination from historical operations was identified during due diligence at a number of sites owned by the acquired companies. The seller, AEP, has indemnified the Partnership for these identified sites. Moreover, AEP has entered into an agreement with a third-party company pursuant to which the remediation costs associated with these sites have been assumed by this third party company that specializes in remediation work. The Partnership does not expect to incur any material liability with these sites; however, there can be no assurance that the third parties who have assumed responsibility for remediation of site conditions will fulfill their obligations. In addition, the Partnership has disclosed possible Clean Air Act monitoring deficiencies it has discovered to the LDEQ and is working with the department to correct these deficiencies and to address modifications to facilities to bring them into compliance. The Partnership does not expect to incur any material environmental liability associated with these issues.

(d) Other

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

On November 15, 2007, Crosstex CCNG Processing Ltd. ("Crosstex Processing"), the Partnership's wholly-owned subsidiary, received a demand letter from Denbury Onshore, LLC ("Denbury"), asserting a claim for breach of contract and seeking payment of approximately $11.4 million in damages. On April 15, 2008, the parties mediated the matter unsuccessfully. On December 4, 2008, Denbury initiated formal arbitration proceedings against Crosstex Processing, Crosstex Energy Services, L.P., Crosstex North Texas Gathering, L.P., and Crosstex Gulf Coast Marketing, Ltd., seeking $11.4 million and additional unspecified damages. On December 23, 2008, Crosstex Processing filed an answer denying Denbury's allegations and a counterclaim seeking a declaratory judgment that its processing plant is uneconomic under the Processing Contract. Crosstex Energy, Crosstex Marketing, and Crosstex Gathering also filed an answer denying Denbury's allegations and asserting that they are improper parties as Denbury's claim is for breach of the Processing Contract and none of these entities is a party to that agreement. Crosstex Gathering also filed a counterclaim seeking approximately $40.0 million in damages for the value of the NGLs it is entitled to under its Gas Gathering Agreement with Denbury. Once the three-person arbitration panel has been named and cleared conflicts, the arbitration panel will hold a preliminary conference with the parties to set a date for the final hearing and other case deadlines and to establish discovery limits. Although it is not possible to predict with certainty the ultimate outcome of this matter, the Partnership does not believe this will have a material adverse effect on its consolidated results of operations or financial position.

The Partnership (or its subsidiaries) is defending eleven lawsuits filed by owners of property located near processing facilities or compression facilities constructed by the Partnership as part of its systems in north Texas. The suits generally allege that the facilities create a private nuisance and have damaged the value of surrounding property. Claims of this nature have arisen as a result of the industrial development of natural gas gathering, processing and treating facilities in urban and occupied rural areas. At this time, five cases are set for trial in 2009. The remaining cases have not yet been set for trial. Discovery is underway. Although it is not possible to predict the ultimate outcomes of these matters, the Partnership does not believe that these claims will have a material adverse impact on its consolidated results of operations or financial condition.

On July 22, 2008, SemStream, L.P. and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code. As of July 22, 2008, SemStream, L.P. owed the Partnership approximately $6.2 million, including approximately $3.9 million for June 2008 sales and approximately $2.2 million for July 2008 sales. The Partnership believes the July sales of $2.2 million will receive "administrative claim" status in the bankruptcy proceeding. The debtor's schedules acknowledge its obligation to Crosstex for an administrative claim in the amount of $2.2 but the allowance of the administrative claim status is still subject to approval of the bankruptcy court in accordance with the administrative claim allowance procedures order in the case. The Partnership evaluated these receivables for collectibility and provided a valuation allowance of $3.1 million during the year ended December 31, 2008.

(17) Segment Information

The Partnership has one reportable segment following the disposition of its Treating assets in October 2009. Therefore, the recasting of segment information for the period ending December 31, 2008 does not require a footnote on segments.

(18) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below.

	First	Second	Third	Fourth	Total
	(In thousands, except per unit data)				
2008					
Revenues	$799,761	$996,833	$855,687	$423,730	$3,076,011
Operating income (loss)	$ 12,464	$ 9,865	$ 4,667	$ (41,156)	$ (14,160)
Discontinued operations	$ 5,551	$ 10,012	$ 6,227	$ 53,022	$ 74,812
Net income attributable to the non-controlling interest	$ 144	$ 50	$ 44	$ 73	$ 311
Net income (loss) attributable to Crosstex Energy, L.P.	$ 3,711	$ 21,742	$ (5,243)	$ (9,439)	$ 10,771
Earnings (loss) per limited partner common unit-basic	$ (3.61)	$ 0.23	$ (0.24)	$ (0.18)	$ (3.19)
Earnings (loss) per limited partner common unit-diluted	$ (3.61)	$ 0.21	$ (0.24)	$ (0.18)	$ (3.19)
Basic and diluted senior subordinated C unit	$ 9.44	$ —	$ —	$ —	$ 9.44
2007					
Revenues	$475,298	$570,765	$571,502	$766,764	$2,384,329
Operating income (loss)	$ (2,522)	$ 7,639	$ 6,276	$ 19,594	$ 30,987
Discontinued operations	$ 6,996	$ 5,514	$ 9,404	$ 9,429	$ 31,343
Net income attributable to the non-controlling interest	$ 19	$ 30	$ 136	$ (25)	$ 160
Net income (loss) attributable to Crosstex Energy, L.P.	$ (5,277)	$ 2,888	$ 2,130	$ 14,148	$ 13,889
Earnings (loss) per limited partner common unit — basic	$ (0.35)	$ (0.06)	$ (0.09)	$ 0.30	$ (0.20)
Earnings (loss) per limited partner common unit — diluted	$ (0.35)	$ (0.06)	$ (0.09)	$ 0.19	$ (0.20)

(19) Condensed Consolidating Financial Statements

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

Schedule II

CROSSTEX ENERGY, L.P.

VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Balance at End of Period
		(In thousands)		
Year ended December 31, 2008 Allowance for doubtful accounts	$ 985	$ 2,670	—	$ 3,655
Year ended December 31, 2007 Allowance for doubtful accounts	$ 618	$ 367	—	$ 985
Year ended December 31, 2006 Allowance for doubtful accounts	$ 259	$ 359	—	$ 618