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

Form 10-K

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

For the fiscal year ended December 31, 2008

or

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

For the transition period from to

Commission file number: 001-33303

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**65-1295427** *(I.R.S. Employer Identification No.)*
1000 Louisiana St, Suite 4300 **Houston, Texas** *(Address of principal executive offices)*	**77002** *(Zip Code)*

(713) 584-1000
(Registrant's telephone number, including area code)

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

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

Securities registered pursuant to section 12(g) of the Act: None

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

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

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

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

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

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

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

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $796.0 million on June 30, 2008, based on $23.05 per unit, the closing price of the Common Units as reported on The NASDAQ Stock Market LLC on such date.

As of February 1, 2009, there were 34,684,000 Common Units, 11,528,231 Subordinated Units and 943,108 General Partner Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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DESCRIPTION

PART I

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries ("we," "us," "our" or the "Partnership")) reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You can typically identify forward-looking statements by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

All statements that are not statements of historical facts, including statements regarding our future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements.

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Item 1A. Risk Factors" as well as the following risks and uncertainties:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL") and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of natural gas drilling around our assets and our success in connecting natural gas supplies to our gathering and processing systems and NGL supplies to our logistics and marketing facilities;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- general economic, market and business conditions; and

- the risks described elsewhere in this Annual Report on Form 10-K (“Annual Report”).

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Annual Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described under the heading Risk Factors in this Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

As generally used in the energy industry and in this Annual Report, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 gallons)
BBtu	Billion British thermal units, a measure of heating value
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
/d	Per day
Gal	Gallons
MBbl	Thousand barrels
Mcf	Thousand cubic feet
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL	Natural gas liquid(s)

Price Index Definitions	
IF-HSC	Inside FERC Gas Market Report, Houston Ship Channel/Beaumont, Texas
IF-NGPL MC	MC Inside FERC Gas Market Report, Natural Gas Pipeline, Mid-Continent
IF-Waha	Inside FERC Gas Market Report, West Texas Waha
NY-HH	NYMEX, Henry Hub Natural Gas
NY-WTI	NYMEX, West Texas Intermediate Crude Oil
OPIS-MB	Oil Price Information Service, Mont Belvieu, Texas

Item 1. Business

Overview

Targa Resources Partners LP (NASDAQ: NGLS) is a growth-oriented Delaware limited partnership formed on October 26, 2006 by our parent, Targa Resources, Inc. (“Targa”), a leading provider of midstream natural gas and NGL services in the U.S., to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are engaged in the business of gathering, compressing, treating, processing and selling natural gas and fractionating and selling NGL and NGL products.

We currently operate in the Fort Worth Basin/Bend Arch in North Texas (the “Fort Worth Basin”), the Permian Basin of West Texas and in Southwest Louisiana. We generally gather natural gas from producers at the wellhead or central delivery points, move the wellhead natural gas through our gathering system, treat and process the natural gas and then sell the resulting residue natural gas and NGLs based on published index market prices.

Since our formation, we have leveraged our relationship with Targa to achieve meaningful growth in our business. In connection with our initial public offering (“IPO”) in February 2007, Targa contributed the assets of the North Texas System located in the Fort Worth Basin (the “North Texas System”) to us. In October 2007, we acquired the assets of the San Angelo Operating Unit System located in the Permian Basin (the “SAOU System”) and the assets of the Louisiana Operating Unit System located in Southwest Louisiana (the “LOU System”) from Targa. We intend to continue to leverage our relationship with Targa to acquire and construct additional midstream energy assets and to utilize the significant experience of Targa’s management team to execute our strategy.

Business Strategies

Our primary objective is to provide increasing cash distributions to our unitholders over time. Our business strategies focus on creating and increasing value for our unitholders through efficient operations, disciplined risk management and prudent growth through organic projects and acquisitions.

Successful execution of larger organic growth projects and acquisitions is highly dependent on our access to the equity and debt capital markets. Given the current challenging conditions in the capital markets and the outlook for weak commodity prices, we expect that growth opportunities will be subject to more stringent evaluation criteria and that expenditure levels will moderate to preserve capital until economic and financial market conditions improve.

We intend to accomplish our primary objective by executing the strategies described below:

- *Increasing the profitability of our existing assets.* With our North Texas System, we have an extensive network of gathering systems and two natural gas processing facilities, which positions us to capitalize on ongoing development from the Barnett Shale and the other Fort Worth Basin formations. The SAOU System is located in the Permian Basin of West Texas, which is characterized by long-lived, multi-horizon oil and gas reserves that have low natural production declines. The LOU System has access to onshore basins in South Louisiana and serves the Lake Charles industrial market. Our assets provide us opportunities to:

  - utilize excess pipeline and plant capacity to connect and process new supplies of natural gas at minimal incremental cost;

  - undertake additional initiatives to improve operating efficiencies and increase processing yields;

  - eliminate bottlenecks to allow for increased throughput;

  - pursue pressure reduction projects to increase volumes of gas to be gathered and processed; and

  - expand our footprint in a cost effective manner.

- *Managing our contract mix to optimize profitability.* The majority of our operating margin is generated pursuant to percent-of-proceeds contracts or similar arrangements which, if unhedged, benefit us in increasing commodity price environments and expose us to a reduction in profitability in decreasing commodity price environments. We believe that if appropriately managed, our current contract mix allows us to optimize our profitability over time. Although we expect to maintain primarily percent-of-proceeds arrangements as a function of historical contract structures and the competitive dynamics of our gathering areas, we continually evaluate the market for attractive fee-based and other arrangements which will further reduce the variability of our cash flows as well as enhance our profitability and competitiveness.

- *Mitigating commodity price exposure through prudent hedging arrangements.* The primary purpose of our commodity price risk management activities is to hedge our exposure to commodity price risk inherent in our contract mix and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. We have hedged the commodity price associated with a portion of our expected natural gas, NGLs and condensate equity volumes for the years 2009 through 2012 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages of our expected equity volumes that are covered by our hedges decrease over time. We have structured our hedges to approximate our actual NGL product composition and to approximate our actual NGL and natural gas delivery points. We do not use crude oil prices to approximate NGL prices for purposes of hedging. We intend to continue to manage our exposure to commodity prices in the future by entering into similar hedge transactions using swaps, collars, purchased puts (or floors) or other hedge instruments as market conditions warrant. During prolonged periods of low commodity prices or low liquidity in forward markets, we may elect to hedge a lower portion of our exposure. Concerns regarding hedge counterparty credit quality may impact our desire or ability to enter into new hedging arrangements.

- *Capitalizing on organic expansion opportunities.* We continually evaluate economically attractive organic expansion opportunities in existing or new areas of operation that will allow us to expand our business.

- *Focusing on producing regions with attractive characteristics.* We seek to focus on those regions and supplies with attractive characteristics, including regions:

  - where treating or processing is required to access end-markets;

  - with a strong base of current production and the potential for future development;

  - where permitting, drilling and workover activity is high;

  - with the potential for long-term acreage dedications; and

  - that can serve as a platform to expand into adjacent areas with existing or new production.

- *Pursuing strategic and accretive acquisitions.* We plan to pursue strategic and accretive acquisition opportunities within the midstream energy industry, both from Targa and from third parties. We will seek acquisitions in our existing areas of operation that provide the opportunity for operational efficiencies, the potential for higher capacity utilization and expansion of existing assets, acquisitions in other related midstream businesses and/or expansion into new geographic areas of operation and, to the extent available, assets with fee-based arrangements. Among the factors we will consider in deciding whether to acquire assets include, but are not limited to, the economic characteristics of the acquisition (such as return on capital and cash flow stability), the region in which the assets are located (both regions contiguous to our areas of operation and other regions with attractive characteristics) and the availability and sources of capital to finance the acquisition. We intend to finance our expansion through a combination of debt and equity, including commercial debt facilities and public and private offerings of debt and equity securities. Current disruptions in the financial markets has made obtaining equity or debt funding on acceptable terms more difficult, which could limit our ability to successfully complete acquisitions.

- *Leveraging our relationship with Targa.* Our relationship with Targa provides us access to its extensive pool of operational, commercial and risk management expertise which enables all of our strategies. In addition, we intend to pursue acquisition opportunities as well as organic growth opportunities with Targa and with Targa's assistance. We may also acquire assets or businesses directly from Targa, which will provide us access to an array of growth opportunities broader than that available to many of our competitors.

Competitive Strengths

We believe that we are well positioned to execute our primary business objective and business strategies successfully because of the following competitive strengths:

- *Affiliation with Targa.* We expect that our relationship with Targa will provide us with significant business opportunities. Targa owns and operates a large integrated platform of midstream assets in oil and natural gas producing regions, including the Permian Basin in West Texas and Southeast New Mexico and the onshore and offshore regions of the Texas and Louisiana Gulf Coast. These operations are integrated with Targa's NGL logistics and marketing business that extends services to customers throughout the U.S. We believe Targa's relationships throughout the energy industry, including with producers of natural gas in the U.S., will help facilitate implementation of our acquisition strategy and other strategies. Targa has indicated that it intends to use us as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets and we expect to have the opportunity, but not the obligation, to acquire such businesses and assets directly from Targa in the future.

- *Strategically located assets.*

  Our North Texas System is one of the largest integrated natural gas gathering, compression, treating and processing systems in the Fort Worth Basin. We believe current levels of natural gas exploration, development and production activities within the Fort Worth Basin present opportunities to generate additional throughput on our system.

  The SAOU System provides us access to the Permian Basin, which is characterized by long-lived, multi-horizon oil and gas reserves that have low natural production declines. The SAOU System has access to liquid market hubs for both natural gas and NGLs.

  The LOU System gathers gas primarily from onshore oil and gas production in Southwest Louisiana in the area around and between Lafayette and Lake Charles, Louisiana. The LOU System's processing plants have direct access to the Lake Charles industrial market through its intrastate pipeline system, providing us the ability to deliver natural gas to industrial users and electric utilities in the Lake Charles area. The LOU System also has access to both interstate natural gas supplies and markets as well as access to the NGL markets of the Louisiana and Texas Gulf Coast.

- *High quality and efficient assets.* Our gathering and processing systems consist of high quality assets that have been well maintained, resulting in low cost, efficient operations. We have implemented state-of-the-art processing, measurement and operations and maintenance technologies. These technologies have allowed us to proactively manage our operations with fewer field personnel resulting in lower costs and minimal downtime. As a result, we believe we have established a reputation in the midstream business as a reliable and cost-effective supplier of services to our customers and have a track record of safe, efficient and reliable operation of our facilities.

- *Low maintenance capital expenditures.* We believe that a relatively low level of maintenance capital expenditures is sufficient for us to continue operations in a safe, prudent and cost-effective manner.

- *Prudent hedging arrangements.* While our percent-of-proceeds gathering and processing contracts subject us to commodity price risk, we have entered into long-term hedges covering the commodity price exposure associated with a significant portion of our near to mid-term expected equity gas, condensate and NGL volumes.

- S*trong producer customer base.* We have a strong producer customer base consisting of both major oil and gas companies and other producers. We believe we have established a reputation as a reliable operator by providing high quality services and focusing on the needs of our customers. Targa also has relationships throughout the energy industry, including with producers of natural gas in the U.S. and has established a positive reputation in the energy business which we believe will assist us in our primary business objectives.

- *Comprehensive package of midstream services.* We provide a comprehensive package of services to natural gas producers, including natural gas gathering, compression, treating, processing and NGL fractionating. We believe our ability to provide these services provides us with an advantage in competing for new supplies of natural gas because we can provide substantially all of the services producers, marketers and others require to move natural gas and NGLs from wellhead to market on a cost-effective basis.

- *Experienced management team.* Targa's executive management team members have over 200 years of combined experience operating, acquiring, integrating and improving the value of midstream natural gas assets and businesses across major supply areas including Texas, Louisiana and the Gulf Coast and have held management positions at companies with midstream assets and commercial operations similar in scale and scope to ours. Several of Targa's executive and senior management team members have worked together effectively in prior roles. In addition, Targa's operations and commercial management team consists of individuals with an average of approximately 25 years of midstream operating experience. Our relationship with Targa provides us with access to significant operational, commercial, technical, risk management and other expertise.

While we have set forth our strategies and competitive strengths above, our business involves numerous risks and uncertainties which may prevent us from executing our strategies or impact the amount of distributions to our unitholders. These risks include the adverse impact of changes in natural gas, NGL and condensate prices, our ability to finance our operations, our ability to access sufficient additional production to replace natural declines in production and our dependence on a single natural gas producer for a significant portion of our natural gas supply. For a more complete description of the risks associated with an investment in us, see "Item 1A. Risk Factors."

Our Relationship with Targa Resources, Inc.

One of our principal strengths is our relationship with Targa, a leading provider of midstream natural gas and NGL services in the U.S. Targa was formed in 2004 by its management team, which consists of former members of senior management of several midstream and other diversified energy companies and Warburg Pincus LLC ("Warburg Pincus"), a private equity firm. In April 2004, Targa purchased the SAOU and LOU Systems from ConocoPhillips Company ("ConocoPhillips"), for $247 million and, in October 2005, Targa purchased substantially all of the midstream assets of Dynegy Inc. ("Dynegy") for approximately $2.5 billion. These transactions formed a large-scale, integrated midstream energy company with the ability to offer a wide range of midstream services to a diverse group of natural gas and NGL producers and customers. As of December 31, 2008, Targa had total assets of approximately $3.6 billion (including the assets of the Partnership, which represent approximately $1.6 billion of this amount).

Targa conducts its business operations through two divisions and reports its results of operations under four segments: Natural Gas Gathering and Processing division, which includes the Partnership, is a single segment consisting of Targa's natural gas gathering and processing facilities, as well as certain fractionation capability integrated within those facilities; and the NGL Logistics and Marketing division, which consists of three segments: Logistics Assets, NGL Distribution and Marketing, and Wholesale Marketing.

Natural Gas Gathering and Processing—Targa gathers and processes natural gas from the Permian Basin, North Texas, the onshore region of the Louisiana Gulf Coast and the Gulf of Mexico. Most of the NGLs Targa processes are supplied through its gathering systems which, in aggregate, consist of approximately 11,000 miles of natural gas pipelines. The remainder is supplied through third party owned pipelines. Targa's processing plants include 16 facilities that it operates (either wholly or jointly) as well as six facilities in which it has an ownership interest but are operated by others. For 2008, these assets processed an average inlet plant volume of approximately 1.8 Bcf/d of natural gas and produced an average of approximately 87 MBbl/d of NGLs, in each case, net to Targa's ownership interests.

NGL Logistics and Marketing—Targa has a significant, integrated NGL logistics and marketing business with net NGL fractionation capacity of approximately 300 MBbl/d and 36 owned and operated storage wells with a net storage capacity of approximately 65 MMBbl and 17 storage, marine and transport terminals with an NGL above ground storage capacity of approximately 900 MBbl. This division uses its extensive platform of integrated assets to fractionate, store, terminal, transport, distribute and market NGLs, typically under fee-based and margin-based arrangements. Its assets are generally connected to and supplied, in part, by its Natural Gas Gathering and Processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana with terminals and transportation assets across the U.S. Targa owns, operates or leases assets in a number of other states, including Alabama, Nevada, California, Florida, Mississippi, Tennessee, New Jersey and Kentucky. The geographic diversity of Targa's assets provides it direct access to many NGL end-users in both its geographic markets as well as markets outside its operating regions via open-access regulated NGL pipelines owned by third parties. Targa also owns 21 pressurized NGL barges, owns and leases approximately 70 transport tractors and owns 100 tank trailers and leases and manages approximately 770 railcars.

Targa has indicated that it intends to use us as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets. Over time, depending on our ability to access to the debt and equity markets, Targa intends to offer us the opportunity to purchase substantially all of its remaining businesses, although it is not obligated to do so. While Targa believes it will be in its best interest to contribute additional assets to us given its significant ownership of limited and general partner interests in us, Targa constantly evaluates acquisitions and dispositions and may elect to acquire, construct or dispose of midstream assets in the future without offering us the opportunity to purchase or construct those assets. We cannot say with any certainty which, if any, opportunities to acquire assets from Targa may be made available to us or if we will choose to pursue any such opportunity. Moreover, Targa is not prohibited from competing with us and routinely evaluates acquisitions and dispositions that do not involve us. In addition, through our relationship with Targa, we have access to a significant pool of management talent, strong commercial relationships throughout the energy industry and access to Targa's broad operational, commercial, technical, risk management and administrative infrastructure.

Targa has a significant indirect interest in our partnership through its ownership of a 24.5% limited partner interest and a 2% general partner interest in us. In addition, Targa owns incentive distribution rights that entitle Targa to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. We are party to an Omnibus Agreement with Targa that governs our relationship with them regarding certain reimbursement and indemnification matters. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Omnibus Agreement." In addition to carrying out operations, our general partner and its affiliates, which are indirectly owned by Targa, employ approximately 950 people, some of whom provide direct support to our operations. We do not have any employees. See "—Employees."

While our relationship with Targa is a significant advantage, it is also a source of potential conflicts. For example, Targa is not restricted from competing with us. Targa owns substantial midstream assets and may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets. See "Item 13. Certain Relationships and Related Transactions, and Director Independence —Conflicts of Interest."

Our Systems

Our natural gas gathering and processing operations are located in and serve parts of three geographic regions: the North Texas System in the Fort Worth Basin, the SAOU System in the Permian Basin and the LOU System in Southwestern Louisiana.

The following table summarizes key ownership and operational information regarding our operating gathering systems and natural gas processing plants, all of which are 100% owned and operated:

Facility	Location	Approximate Gross Processing Capacity (MMcf/d)	2008 Approximate Gross Inlet Throughput Volume (MMcf/d)	2008 Approximate Gross NGL Production (MBbl/d)	Process Type (3)
North Texas System					
Chico (1)	Wise, TX	265			Cryo
Shackelford	Shackelford,TX	13			Cryo
	Area Total	278	162.8	19.0	
SAOU System					
Mertzon	Irion, TX	48			Cryo
Sterling	Sterling, TX	62			Cryo
Conger (2)	Sterling, TX	25			Cryo
	Area Total	135	90.3	14.1	
LOU System					
Gillis (1)	Calcasieu,LA	180			Cryo
Acadia	Acadia, LA	80			Cryo
	Area Total	260	168.1	9.0	

(1) The Chico and Gillis plants have fractionation capacities of approximately 15 MBbl/d and 13 MBbl/d.
(2) The Conger plant is not currently operating, but is on standby and can be quickly reactivated on short notice to meet additional needs for processing capacity.
(3) Cryo — Cryogenic Expander.

The North Texas System

The North Texas System includes two interconnected gathering systems with approximately 4,100 miles of pipelines, covering portions of 12 counties and 5,700 square miles, that gather wellhead natural gas for the Chico and Shackelford natural gas processing facilities. During 2008, the North Texas System gathered approximately 169 MMcf/d of natural gas.

Gathering. The Chico Gathering System consists of approximately 2,000 miles of primarily low-pressure gathering pipelines. Wellhead natural gas is either gathered for the Chico plant located in Wise County, Texas and then compressed for processing or it is compressed in the field at numerous compressor stations and then moved via one of several high-pressure gathering pipelines to the Chico plant. The Shackelford Gathering System consists of approximately 2,100 miles of intermediate-pressure gathering pipelines which gather wellhead natural gas largely for the Shackelford plant in Albany, Texas. Natural gas gathered from the northern and eastern portions of the Shackelford Gathering System is typically compressed in the field at numerous compressor stations and then transported via a high-pressure 32-mile, 10-inch diameter pipeline, called the Interconnect Pipeline, to the Chico plant for processing.

Processing. The Chico processing plant includes two cryogenic processing trains with a combined capacity of approximately 265 MMcf/d and an NGL fractionator with the capacity to fractionate up to approximately 15 MBbl/d of raw NGL mix. The Shackelford plant is a cryogenic plant with a nameplate capacity of approximately 15 MMcf/d, but effective capacity is limited to approximately 13 MMcf/d due to capacity constraints on the residue gas pipeline that serves the facility. Our produced NGL is primarily shipped via pipeline to Targa's Mont Belvieu facility for fractionation. Residue gas and NGL are shipped via several interstate and intrastate natural gas pipelines.

The SAOU System

Covering portions of 10 counties and approximately 4,000 square miles in West Texas, the SAOU System includes approximately 1,350 miles of pipeline in the Permian Basin that deliver wellhead natural gas to the Mertzon, Sterling and Conger processing plants. During 2008, the system gathered approximately 99 MMcf/d of natural gas, including approximately 6 MMcf/d purchased from a third party gatherer.

Gathering. The SAOU System is connected to numerous producing wells and/or central delivery points. The system has approximately 850 miles of low-pressure gathering systems and approximately 500 miles of high-pressure gathering pipelines to deliver the natural gas to our processing plants. The gathering system has numerous compressor stations to inject low-pressure gas into the high-pressure pipelines.

Processing. The SAOU System includes two currently operating refrigerated cryogenic processing plants, the Mertzon plant and the Sterling plant, which have an aggregate processing capacity of approximately 110 MMcf/d. The system also includes the Conger cryogenic plant with a capacity of approximately 25 MMcf/d, which is on standby and can be quickly reactivated on short notice and minimal incremental cost to meet additional needs for processing capacity. NGL produced by the SAOU system are primarily shipped via pipeline to Targa's Mont Belvieu facility for fractionation. Residue gas and NGL are shipped via several interstate and intrastate pipelines.

The LOU System

The LOU System consists of approximately 850 miles of gathering system pipelines, covering approximately 3,800 square miles in Southwest Louisiana. During 2008, the system gathered approximately 178 MMcf/d of natural gas, including approximately 53 MMcf/d purchased from third party pipeline systems.

Gathering. The LOU System is connected to numerous producing wells and/or central delivery points in the area between Lafayette and Lake Charles, Louisiana. The gathering system is a high-pressure gathering system that delivers natural gas for processing to either the Acadia or Gillis plants via three main trunk lines.

Processing. The LOU System includes the Gillis and Acadia processing plants, both of which are cryogenic plants. These processing plants have an aggregate processing capacity of approximately 260 MMcf/d. In addition, the Gillis plant has integrated fractionation with operating capacity of approximately 13 MBbl/d of capacity. The residue gas produced from the processing plants has direct access to the Lake Charles industrial market through the system's intrastate pipeline system. This intrastate system has the ability to deliver natural gas to industrial users and electric utilities in the Lake Charles area through both medium pressure and high pressure pipelines.

The Combined Systems

Our aggregate gas supply contract profile for 2008 on a volume basis was approximately 77% percent-of-proceeds contracts, 20% wellhead purchase/keep whole contracts, 2% fee-based contracts and 1% hybrid contracts. Substantially all of the wellhead and keep-whole contracts are associated with the portion of the LOU System's supply comprising processable gas purchased from other pipeline systems, typically under short term contracts. The LOU System's industrial customers can readily accept richer (higher Btu) gas, thereby providing the system with operational and commercial flexibility to reject or bypass NGLs if unexpected operating conditions occur or if NGLs are more valuable as natural gas. The above factors mitigate the commodity price risk typically associated with wellhead purchase or keep-whole contracts.

Our largest natural gas supplier for 2008 was Crosstex Energy ("Crosstex"), a gas gatherer who accounted for approximately 12% of our supply, which sells gas to us on a spot basis. In addition, purchases from ConocoPhillips accounted for approximately 11% of our combined gathering volumes in 2008. The loss of all or even a portion of the natural gas volumes supplied by these customers or the extension or replacement of these contracts on less favorable terms, if at all, as a result of competition or otherwise, could reduce our revenue or increase our cost for product purchases.

Competition

We face strong competition in acquiring new natural gas supplies. Competition for natural gas supplies is primarily based on the location of gathering and processing facilities, pricing arrangements, reputation, efficiency, flexibility, reliability and access to end-use markets or liquid marketing hubs. Competitors to our gathering and processing operations include other natural gas gatherers and processors, master limited partnerships and oil and gas producers. Our major competitors for natural gas supplies in our current operating regions include Atlas Gas Pipeline Company, Copano Energy. L.L.C ("Copano"), WTG Gas Processing L.P. ("WTG"), DCP Midstream Partners LP ("DCP Midstream"), Devon Energy Corp, Enbridge Inc., GulfSouth Pipeline Company, LP, Hanlan Gas Processing, Ltd., J W Operating Company, Louisiana Intrastate Gas and several interstate pipeline companies. Some of our competitors have greater financial resources than we possess.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Gathering Pipeline Regulation

Our natural gas gathering operations are typically subject to ratable take and common purchaser statutes in the states in which we operate. The common purchaser statutes generally require our gathering pipelines to purchase or take without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. The rates we charge for gathering are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Section 1(b) of the Natural Gas Act of 1938 ("NGA"), exempts natural gas gathering facilities from regulation as a natural gas company by the Federal Energy Regulatory Commission ("FERC") under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and servicesAdditional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

In 2007, Texas enacted new laws regarding rates, competition and confidentiality for natural gas gathering and transmission pipelines ("Competition Statute") and new informal complaint procedures for challenging determinations of lost and unaccounted for gas by gas gatherers, processors and transporters ("LUG Statute"). The Competition Statute gives the Railroad Commission of Texas ("RRC') the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and transportation pipelines in formal rate proceedings. This statute also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Statute modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. Such statute also extends the types of information that can be requested and provides the RRC with the authority to make determinations and issue orders in specific situations. We cannot predict what effect, if any, these statutes might have on our future operations in Texas.

Intrastate Pipeline Regulation

Though our natural gas intrastate pipelines are not subject to regulation by FERC as natural gas companies under the NGA, our intrastate pipelines may be subject to certain FERC-imposed daily scheduled flow and capacity posting requirements depending on the volume of flows in a given period and the design capacity of the pipelines' receipt and delivery meters. See below the discussion of "Other Federal Laws and Regulations Affecting Our Industry – FERC Market Transparency Rules."

Our Texas intrastate pipeline, Targa Intrastate Pipeline LLC ("Targa Intrastate"), owns the intrastate pipeline that transports natural gas from our Shackelford processing plant to an interconnect with Atmos-Texas that in turn delivers gas to the West Texas Utilities Company's Paint Creek Power Station. Targa Intrastate also owns a 1.65 mile, 10-inch diameter intrastate pipeline that transports natural gas from a third party gathering system into the Chico System in Denton, County, Texas. Targa Intrastate is a gas utility subject to regulation by the RRC and has a tariff on file with such agency.

Our Louisiana intrastate pipeline, Targa Louisiana Intrastate LLC, or TLI, owns an approximately 60-mile intrastate pipeline system that receives all of the natural gas it transports within or at the boundary of the State of Louisiana. Because all such gas ultimately is consumed within Louisiana, and since the pipeline's rates and terms of service are subject to regulation by the Office of Conservation of the Louisiana Department of Natural Resources ("DNR"), the pipeline qualifies as a Hinshaw pipeline under Section 1(c) of the NGA and thus is exempt from full FERC regulation. On November 20, 2008, FERC issued a Notice of Inquiry ("NOI") seeking comment on whether it should impose additional posting and reporting requirements on Hinshaw pipelines providing interstate service under limited blanket certificates and intrastate pipelines providing interstate service under Section 311 of the Natural Gas Policy Act, or NGPA. If FERC issues a proposed rulemaking based on the NOI, it would not cover TLI as currently written, as TLI only provides service governed by the Hinshaw amendment. TLI does not provide interstate service pursuant to any limited blanket certificate. FERC has not yet determined whether a rulemaking proceeding is necessary and we cannot predict what, if any, rules FERC will propose as a result of its inquiry or the ultimate impact of any such regulatory changes to our Hinshaw pipeline.

Texas and Louisiana have adopted complaint-based regulation of intrastate natural gas transportation activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to pipeline access and rate discrimination. The rates we charge for intrastate transportation are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Regulation of our NGL intrastate pipelines. Our intrastate NGL pipelines in Louisiana gather raw NGL streams that we own from processing plants in Louisiana and deliver such streams to our Gillis fractionator in Lake Charles, Louisiana, where the raw NGL streams are fractionated into various products. We deliver such refined products (ethane, propane, butane and natural gasoline) out of our fractionator to and from Targa-owned storage, to other third party facilities to various third party pipelines in Louisiana. These pipelines are not subject to FERC regulation or rate regulation by the DNR, but are regulated by United States Department of Transportation (“DOT”) safety regulations.

Natural Gas Processing

Our natural gas gathering and processing operations are not presently subject to FERC regulation. Starting May 1, 2009, we report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year. See below the discussion of “FERC Market Transparency Rules.” There can be no assurance that our processing operations will continue to be exempt from other FERC regulation in the future.

Availability, Terms and Cost of Pipeline Transportation

Our processing facilities and our marketing of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and, if a complaint is filed, state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to our processing operations and our natural gas and NGL marketing operations. We do not believe that we would be affected by any such FERC action materially differently than other natural gas processors and natural gas and NGL marketers with whom we compete.

The ability of our processing facilities and pipelines to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council (the “NGC+ Work Group”), or to explain how and why their tariff provisions differ. We do not believe that the adoption of the NGC+ Work Group’s gas quality interim guidelines by a pipeline that either directly or indirectly interconnects with our facilities would materially affect our operations. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group’s interim guidelines for such an interconnecting pipeline.

Sales of Natural Gas and NGLs

The price at which we buy and sell natural gas and NGLs is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodity Futures Trading Commission (“CFTC”). See below the discussion of “Other Federal Laws and Regulations Affecting Our Industry – Energy Policy Act of 2005.” Starting May 1, 2009, we may be required to report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year. See below the discussion “FERC Market Transparency Rules.” Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Other State and Local Regulation of Our Operations

Our business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters. For additional information regarding the potential impact of federal, state or local regulatory measures on our business, see “Item 1A. Risk Factors— Risks Related to Our Business.”

Other Federal Laws and Regulation Affecting Our Industry

Energy Policy Act of 2005

The Domenici-Barton Energy Policy Act of 2005 (“EP Act 2005”) is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EP Act 2005 amends the NGA to add an anti- market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act 2005 provides the FERC with the power to assess civil penalties of up to $1 million per day for violations of the NGA and $1 million per violation per day for violations of the NGPA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. In 2006, FERC issued Order 670 to implement the anti-market manipulation provision of EP Act 2005. Order 670 makes it unlawful to: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit any statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. Order 670 does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704 and the daily schedule flow and capacity posting requirements under Order 720. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC’s NGA enforcement authority.

FERC Market Transparency Rules

In 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (“Order 704”). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers, are now required to report, on May 1 of each year, beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order 704.

On November 20, 2008, FERC issued a final rule on daily scheduled flows and capacity posting requirements (“Order 720”). Under Order 720, certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three (3) calendar years, are required to post daily certain information regarding the pipeline’s capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu per day. Requests for clarification and rehearing of Order 720 have been filed at FERC and a decision on those requests is pending.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other midstream natural gas companies with whom we compete.

Environmental, Health and Safety Matters

General

Our operations are subject to stringent and complex federal, state and local laws and regulations pertaining to health, safety and the environment. For more information on our operations, see “Item 1. Business—Our Systems”. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. These laws and regulations may, among other things, require the acquisition of various permits to conduct regulated activities, require the installation of pollution control equipment or otherwise restrict the way we can handle or dispose of our wastes; limit or prohibit construction activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial action to mitigate pollution conditions caused by our operations or attributable to former operations; and enjoin some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations. Failure to comply with these laws and regulations may result in assessment of administrative, civil and criminal penalties, the imposition of removal or remedial obligations and the issuance of injunctions limiting or prohibiting our activities.

We have implemented programs and policies designed to keep our pipelines, plants and other facilities in compliance with existing environmental laws and regulations. The clear trend in environmental regulation, however, is to place more restrictions and limitations on activities that may affect the environment and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that the current conditions will continue in the future.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, (“CERCLA” or the “Superfund” law) and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these “responsible persons” may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the federal Environmental Protection Agency (“EPA”) and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that are regulated as “hazardous substances” under CERCLA or similar state statutes and, as a result, may be jointly and severally liable under CERCLA or such statutes for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate solid wastes, including hazardous wastes that are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations we generate petroleum product wastes and ordinary industrial wastes such as paint wastes, waste solvents and waste compressor oils that are regulated as hazardous wastes. Certain materials generated in the exploration, development or production of crude oil and natural gas are excluded from RCRA's hazardous waste regulations. However, it is possible that future changes in law or regulation could result in these wastes, including wastes currently generated during our operations, being designated as "hazardous wastes" and therefore subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses as well as those of the oil and gas industry in general.

We currently own or lease and have in the past owned or leased, properties that for many years have been used for midstream natural gas and NGL activities. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Air Emissions

The Clean Air Act, as amended and comparable state laws and regulations restrict the emission of air pollutants from many sources, including processing plants and compressor stations and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. We are currently reviewing the air emissions monitoring systems at certain of our facilities. We may be required to incur capital expenditures in the next few years to implement various air emissions leak detection and monitoring programs as well as to install air pollution control equipment or non-ambient storage tanks as a result of our review or in connection with maintaining, amending or obtaining operating permits and approvals for air emissions. We currently believe, however, that such requirements will not have a material adverse affect on our operations.

Global Warming and Climate Control

In response to concerns suggesting that emissions of certain gases, commonly referred to as "greenhouse gases" (including carbon dioxide ("CO_2") and methane), are contributing to the warming of the Earth's atmosphere, the United States Congress has been considering legislation to reduce such emissions. In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or greenhouse gas cap and trade programs. As an alternative to cap and trade programs, Congress may consider the implementation of a carbon tax program. The cap and trade programs could require major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations (e.g., compressor stations) or from combustion of fuels (e.g., natural gas or NGLs) we process. Depending on the design and implementation of carbon tax programs, our operations could face additional taxes and higher cost of doing business. Although we would not be impacted to a greater degree than other similarly situated gatherers and processors of natural gas or NGLs, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the natural gas and NGLs we gather and process.

Also, as a result of the U.S. Supreme Court’s decision in 2007 in Massachusetts, et al. v. EPA, the EPA may regulate greenhouse gas emissions from mobile sources such as cars and trucks even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court’s holding in Massachusetts that greenhouse gases including CO_2 fall under the federal Clean Air Act’s definition of “air pollutant” may also result in future regulation of CO_2 and other greenhouse gas emissions from stationary sources. In July 2008, EPA released an “Advance Notice of Proposed Rulemaking” regarding possible future regulation of greenhouse gas emissions under the Clean Air Act, in response to the Supreme Court's decision in *Massachusetts*. In the notice, EPA evaluated the potential regulation of greenhouse gases under the Clean Air Act and other potential methods of regulating greenhouse gases. Although the notice did not propose any specific, new regulatory requirements for greenhouse gases, it indicates that federal regulation of greenhouse gas emissions could occur in the near future even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such new federal or state restrictions on emissions of CO_2 that may be imposed in areas in which we conduct business could also have an adverse affect on our cost of doing business and demand for the natural gas and NGLs we gather and process.

Water Discharges

The Federal Water Pollution Control Act, as amended (“Clean Water Act” or “CWA”) and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff. The CWA and analogous state laws can impose substantial civil and criminal penalties for non-compliance including spills and other non-authorized discharges.

The Oil Pollution Act of 1990, as amended (“OPA”), which amends the CWA, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A “responsible party” under OPA includes owners and operators of onshore facilities, such as our plants and our pipelines. Under OPA, owners and operators of facilities that handle, store, or transport oil are required to develop and implement oil spill response plans, and establish and maintain evidence of financial responsibility sufficient to cover liabilities related to an oil spill for which such parties could be statutorily responsible. We believe that we are in substantial compliance with the CWA, OPA and analogous state laws.

Endangered Species Act

The federal Endangered Species Act, as amended (“ESA”), restricts activities that may affect endangered or threatened species or their habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Pipeline Safety

The pipelines we use to gather and transport natural gas and transport NGLs are subject to regulation by the United States Department of Transportation, or the DOT, under the Natural Gas Pipeline Safety Act of 1968, as amended, or NGPSA, with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas and NGL pipeline facilities. Pursuant to these acts, the DOT has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Where applicable, the NGPSA and HLPSA require any entity that owns or operates pipeline facilities to comply with the regulations under these acts, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

Our pipelines are also subject to regulation by DOT under the Pipeline Safety Improvement Act of 2002, which was amended by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES Act"). DOT, through the Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a series of rules, which require pipeline operators to develop and implement integrity management programs for gas transmission pipelines that, in the event of a failure, could affect "high consequence areas." "High consequence areas" are currently defined as areas with specified population densities, buildings containing populations of limited mobility and areas where people gather that are located along the route of a pipeline. Similar rules are also in place for operators of hazardous liquid pipelines including lines transporting NGLs and condensates.

In addition, states have adopted regulations, similar to existing DOT regulations, for intrastate gathering and transmission lines. Texas and Louisiana have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. We currently estimate an annual average cost of $0.4 million for years 2009 through 2011 to perform necessary integrity management program testing on our pipelines required by existing DOT and state regulations. This estimate does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. However, we do not expect that any such costs would be material to our financial condition or results of operations.

More recently, in September 2008, PHMSA issued a proposed rule mandated by the PIPES Act focusing on how human interactions of control room personnel, such as avoidance of error or the performance of mitigating actions, may impact pipeline system integrity. Among other things, the proposed rule would require operators of hazardous liquid and gas pipelines to amend their existing written operations and maintenance procedures, operator qualification programs and emergency plans to take into account such items as specificity of the responsibilities and roles of control room personnel; listing of planned pipeline-related occurrences during a particular shift that may be easily shared with other controllers during a shift turnover; establishment of appropriate shift rotations to protect against controller fatigue; and development of appropriate communications between controllers, management and field personnel when planning and implementing changes to pipeline equipment or operations. While we do not anticipate that the rule, as proposed, will result in substantial costs with respect to our operations, the rule is not yet finalized and thus we cannot provide assurance on how significant an impact the rule ultimately will have on our operations, once it is adopted.

Employee Health and Safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to ground leases between us, as lessee and the fee owner of the lands, as lessors and we believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to any material lease, easement, right-of-way, permit or lease and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Targa may continue to hold record title to portions of certain assets until we make the appropriate filings in the jurisdictions in which such assets are located and obtain any consents and approvals that are not obtained prior to transfer. Such consents and approvals would include those required by federal and state agencies or political subdivisions. In some cases, Targa may, where required consents or approvals have not been obtained, temporarily hold record title to property as nominee for our benefit and in other cases may, on the basis of expense and difficulty associated with the conveyance of title, cause its affiliates to retain title, as nominee for our benefit, until a future date. We anticipate that there will be no material change in the tax treatment of our common units resulting from the holding by Targa of title to any part of such assets subject to future conveyance or as our nominee.

Employees

To carry out its operations, Targa employs approximately 950 people, some of whom provide direct support for our operations. None of these employees are covered by collective bargaining agreements. Targa considers its employee relations to be good. We do not have any employees.

Available Information

We make certain filings with the Securities and Exchange Commission ("SEC"), including our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through our website, *http://www.targaresources.com*, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through (1) the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549, (2) by calling 1-800-SEC-0330 and (3) on the internet at *http://www.sec.gov*. Our press releases and recent analyst presentations are also available on our website.

Item 1A. *Risk Factors*

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. The nature of our business activities subject us to certain hazards and risks. You should consider carefully the following risk factors together with all of the other information contained in this report. Additional risks not presently known to us or which we consider immaterial based on information currently available to us may also materially adversely affect us. If any of the following risks were actually to occur, then our business, financial condition or results of operations could be materially adversely affected.

Risks Related to Our Business

We may not be able to obtain funding or obtain funding on acceptable terms because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

Global financial markets and economic conditions have been and continue to be, disrupted and volatile. The debt and equity capital markets have been exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made and will likely continue to make, it difficult to obtain funding.

In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining funds from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers.

In addition, in October 2008, Lehman Brothers Commercial Bank (“Lehman Bank”) defaulted on a borrowing request under our senior secured revolving credit facility (“credit facility”) which effectively reduced our total commitments under our credit facility by approximately $10.0 million. We can provide no assurance that other lending counterparties will be willing or able to meet their existing funding obligations under our credit facility.

Due to these factors, we cannot be certain that funding will be available, if needed and to the extent required, on acceptable terms. If funding is not available when needed or is available only on unfavorable terms, we may be unable to meet our business funding requirements, grow our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues and results of operations.

Our substantial amount of indebtedness could adversely affect our financial position.

We currently have a substantial amount of indebtedness. As of December 31, 2008 we had approximately $696.8 million of total indebtedness outstanding**,** approximately $9.7 million of letters of credit outstanding and $342.5 million of additional borrowing capacity under our credit facility. In October 2008, one of the lenders under our credit facility, Lehman Bank, defaulted on a borrowing request. As a result, we believe the total commitments under the credit facility have been effectively reduced by approximately $10.0 million. Our credit facility allows us to request increases in the commitments under the credit facility of up to $150 million. We may also incur additional indebtedness in the future.

Our substantial indebtedness may:

- make it difficult for us to satisfy our financial obligations, including making scheduled principal and interest payments on our indebtedness;

- limit our ability to borrow additional funds for working capital, capital expenditures, acquisitions or other general business purposes;

- limit our ability to use our cash flow or obtain additional financing for future working capital, capital expenditures, acquisitions or other general business purposes;
- require us to use a substantial portion of our cash flow from operations to make debt service payments;
- limit our flexibility to plan for or react to, changes in our business and industry;
- place us at a competitive disadvantage compared to our less leveraged competitors; and
- increase our vulnerability to the impact of adverse economic and industry conditions.

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to service our debt depends upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions; reducing or delaying our business activities, investments, acquisitions or capital expenditures; selling assets; restructuring or refinancing our debt; or seeking additional equity capital. We may not be able to affect any of these actions on satisfactory terms or at all. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations —Liquidity and Capital Resources.”

Our cash flow is affected by supply and demand for natural gas and NGL products and by natural gas and NGL prices and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units.

Our operations can be affected by the level of natural gas and NGL prices and the relationship between these prices. The prices of natural gas and NGLs have been volatile and we expect this volatility to continue. Our future cash flow may be materially adversely affected if we experience significant, prolonged pricing deterioration and we may be unable to maintain our current level of distributions. The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include demand for these commodities, which fluctuate with changes in market and economic conditions and other factors, including:

- the impact of seasonality and weather;
- general economic conditions and the economic conditions impacting our primary markets;
- the economic conditions of our customers;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, liquefied natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems and storage for residue natural gas and NGLs;
- the availability and marketing of competitive fuels and/or feedstocks;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. For the year ended December 31, 2008, our percent-of-proceeds arrangements accounted for approximately 77% of our gathered natural gas volume. Under percent-of-proceeds arrangements, we generally process natural gas from producers and remit to the producers an agreed percentage of the proceeds from the sale of residue gas and NGL products at market prices or a percentage of residue gas and NGL products at the tailgate of our processing facilities. In some percent-of-proceeds arrangements, we remit to the producer a percentage of an index or index-based price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. Under these types of arrangements, our revenues and our cash flows increase or decrease, whichever is applicable, as the prices of natural gas, NGL and crude oil fluctuate. For additional information regarding our hedging activities, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk —Commodity Price Risk.”

Because of the natural decline in production from existing wells in our operating regions, our success depends on our ability to obtain new sources of supplies of natural gas and NGLs, which depends on certain factors beyond our control. Any decrease in supplies of natural gas or NGLs could adversely affect our business and operating results.

Our gathering systems are connected to natural gas wells from which production will naturally decline over time, which means that our cash flows associated with these wells will likely also decline over time. To maintain or increase throughput levels on our gathering systems and the utilization rate at our processing plants and our treating and fractionation facilities, we must continually obtain new natural gas and NGL supplies. A material decrease in natural gas production from producing areas on which we rely, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of natural gas that we process and NGL products delivered to our fractionation facilities. Our ability to obtain additional sources of natural gas and NGL depends, in part, on the level of successful drilling and production activity near our gathering systems. We have no control over the level of such activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their drilling or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, availability of drilling rigs, other production and development costs and the availability and cost of capital.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling and production activity generally decreases as oil and natural gas prices decrease. Prices of oil and natural gas have been extremely volatile and we expect this volatility to continue. Energy commodity prices and demand have recently declined substantially, leading many exploration and production companies, including several in our areas of operation, to announce reduced capital expenditure levels for 2009 and could lead producers in our areas of operation to shut-in wells during the coming year. Consequently, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. Reductions in exploration and production activity, competitor actions or shut-ins by producers in the areas in which we operate may prevent us from obtaining new supplies of natural gas to replace the natural decline in volumes from existing wells, which could result in reduced volumes through our facilities and reduced utilization of our gathering, treating, processing and fractionation assets. Should reductions negatively impact our results of operations, they may impair our ability to make distributions to our unitholders.

If we fail to balance our purchases of natural gas and our sales of residue gas and NGLs, our exposure to commodity price risk will increase.

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

Our hedging activities may not be effective in reducing the variability of our cash flows and may, in certain circumstances, increase the variability of our cash flows. Moreover, our hedges may not fully protect us against volatility in basis differentials. Finally, the percentage of our expected equity commodity volumes that are hedged decreases substantially over time.

We have entered into derivative transactions related to only a portion of our equity volumes. As a result, we will continue to have direct commodity price risk to the unhedged portion. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our hedges, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our liquidity. The percentages of our expected equity volumes that are covered by our hedges decrease over time. To the extent we hedge our commodity price risk, we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. The derivative instruments we utilize for these hedges are based on posted market prices, which may be higher or lower than the actual natural gas, NGLs and condensate prices that we realize in our operations. These pricing differentials may be substantial and could materially impact the prices we ultimately realize. In addition, current market and economic conditions may adversely affect our hedge counterparties' ability to meet their obligations. Given the current volatility in the financial and commodity markets, we may experience defaults by our hedge counterparties in the future. As a result of these and other factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows and in certain circumstances may actually increase the variability of our cash flows. For additional information regarding our hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk."

We depend on two natural gas producers for a significant portion of our supply of natural gas. The loss of these customers or the replacement of their contracts on less favorable terms could result in a decline in our volumes, revenues and cash available for distribution.

Our largest natural gas supplier for 2008 was Crosstex, a gas gatherer who accounted for approximately 12% of our supply, which sells gas to us on a spot basis. In addition, purchases from ConocoPhillips accounted for approximately 11% of our combined gathering volumes in 2008. The loss of all or even a portion of the natural gas volumes supplied by these customers or the extension or replacement of these contracts on less favorable terms, if at all, as a result of competition or otherwise, could reduce our revenue or increase our cost for product purchases, impairing our ability to make distributions to our unitholders.

If third party pipelines and other facilities interconnected to our natural gas pipelines and processing facilities become partially or fully unavailable to transport natural gas and NGLs, our revenues could be adversely affected.

We depend upon third party pipelines, storage and other facilities that provide delivery options to and from our pipelines and processing facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within our control. If any of these third party facilities become partially or fully unavailable or if the quality specifications for their pipelines or facilities change so as to restrict our ability to use them, our revenues and cash available for distribution could be adversely affected.

If future acquisitions do not perform as expected, our future financial performance may be negatively impacted.

Acquisitions may significantly increase our size and diversify the geographic areas in which we operate. We can not assure you that we will achieve the desired affect from acquisitions we may complete in the future. In addition, failure to assimilate future acquisitions could adversely affect our financial condition and results of operations.

Our acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographic area;

- the risk that natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the failure to realize expected profitability or growth;
- the failure to realize any expected synergies and cost savings; and
- coordinating geographically disparate organizations, systems and facilities.

Further unexpected costs and challenges may arise whenever businesses with different operations or management are combined and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operations may change significantly and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

We are exposed to the credit risk of Targa and any material nonperformance by Targa could reduce our ability to make distributions to our unitholders.

We have entered into purchase agreements with Targa pursuant to which Targa will purchase (i) all of the North Texas System's natural gas, NGLs and high-pressure condensate for a term of 15 years and (ii) substantially all of the SAOU and LOU Systems' natural gas for a term of 15 years and NGLs for a term of one year. Targa also manages the SAOU and LOU Systems' natural gas sales to third parties under contracts that remain in the name of the SAOU and LOU Systems. We are also party to an amended and restated Omnibus Agreement with Targa which addresses, among other things, the provision of general and administrative and operating services to us. Targa's corporate credit ratings as assigned by Moody's and Standard & Poors as of February 25, 2009 are B1 and B, which are speculative ratings. These speculative ratings signify a higher risk that Targa will default on its obligations, including its obligations to us, than does an investment grade credit rating. Any material nonperformance under the omnibus and purchase agreements by Targa could materially and adversely impact our ability to operate and make distributions to our unitholders.

Our general partner is an obligor under and subject to a pledge related to, Targa's credit facility; in the event Targa is unable to meet its obligations under that facility or is declared bankrupt, Targa's lenders may gain control of our general partner or, in the case of bankruptcy, our partnership may be dissolved.

Targa Resources GP LLC, our general partner, is an obligor under and all of its assets and Targa's ownership interest in it are subject to a lien related to, Targa's credit facility. In the event Targa is unable to satisfy its obligations under its credit facility and the lenders foreclose on their collateral, the lenders will own our general partner and all of its assets, which include the general partner interest in us and our incentive distribution rights. In such event, the lenders would control our management and operation. Moreover, in the event Targa becomes insolvent or is declared bankrupt, our general partner may be deemed insolvent or declared bankrupt as well. Under the terms of our partnership agreement, the bankruptcy or insolvency of our general partner will cause a dissolution of our partnership.

Our industry is highly competitive and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large oil, natural gas and NGL companies that have greater financial resources and access to supplies of natural gas and NGLs than we do. Some of these competitors may expand or construct gathering, processing and transportation systems that would create additional competition for the services we provide to our customers. In addition, our customers who are significant producers of natural gas may develop their own gathering, processing and transportation systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions.

Typically do not obtain independent evaluations of natural gas reserves dedicated to our gathering pipeline systems; therefore, volumes of natural gas on our systems in the future could be less than we anticipate.

We typically do not obtain independent evaluations of natural gas reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves dedicated to our gathering systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems is less than we anticipate and we are unable to secure additional sources of natural gas, then the volumes of natural gas transported on our gathering systems in the future could be less than we anticipate. A decline in the volumes of natural gas on our systems could have a material adverse effect on our business, results of operations and financial condition and our ability to make cash distributions to our unitholders.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel markets could materially adversely affect our business, results of operations and financial condition.

The NGL products we produce have a variety of applications, including petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry-specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand recently observed due to lower activity in the automobile and construction industries), increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services. Our NGL products and their demand are affected as follows:

Ethane. Ethane is typically supplied as purity ethane and as part of ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing.

Propane. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of warmer-than-normal weather.

Normal Butane. Normal butane is used in the production of isobutane, as a refined product blending component, as a fuel gas, either alone or in a mixture with propane and in the production of ethylene and propylene. Changes in the composition of refined products resulting from governmental regulation, changes in feedstocks, products and economics, demand for heating fuel and for ethylene and propylene, could adversely affect demand for normal butane.

Isobutane. Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

Natural Gasoline. Natural gasoline is used as a blending component for certain refined products and as a feedstock used in the production of ethylene and propylene. Changes in the composition of motor gasoline resulting from governmental regulation and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with products from global markets. Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline at the markets we access for any of the reasons stated above could adversely affect demand for the services we provide as well as NGL prices, which would negatively impact our results of operations and financial condition.

We do not own most of the land on which our pipelines and compression facilities are located, which could disrupt our operations.

We do not own most of the land on which our pipelines and compression facilities are located and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or leases or if such rights of way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere, reduce our revenue and impair our ability to make distributions to our unitholders.

Weather may limit our ability to operate our business and could adversely affect our operating results.

The weather in the areas in which we operate can cause disruptions and in some cases suspension of our operations. Examples include unseasonably wet weather, extended periods of below-freezing weather and hurricanes. Disruptions or suspension of our operations caused by weather could adversely affect our operating results.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

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

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, explosions and acts of terrorism;
- inadvertent damage from third parties, including from construction, farm and utility equipment;
- leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury, loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. For example, Hurricanes Katrina and Rita damaged gathering systems, processing facilities, NGL fractionators and pipelines along the Gulf Coast, including certain of our facilities. These hurricanes disrupted the operations of our customers in August and September 2005, which curtailed or suspended the operations of various energy companies with assets in the region. The Louisiana and Texas Gulf Coast was similarly impacted in September 2008 as a result of Hurricanes Gustav and Ike. We are not fully insured against all risks inherent to our business. We are not insured against all environmental accidents that might occur which may include toxic tort claims, other than incidents considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial condition could be adversely affected. In addition, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially and could escalate further. For example, following Hurricanes Katrina and Rita, insurance premiums, deductibles and co-insurance requirements increased substantially and terms generally are less favorable than terms that could be obtained prior to such hurricanes. The insurance market conditions have worsened as a result of the losses sustained from Hurricanes Gustav and Ike in September 2008. As a result, we expect to experience further increases in deductibles and premiums and further reductions in coverage and limits, with some coverages unavailable at any cost.

Increases in interest rates could adversely affect our business.

In addition to our exposure to commodity prices, we have significant exposure to increases in interest rates. As of December 31, 2008, we had approximately $487.8 million of debt outstanding under our credit facility at variable interest rates. Our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Interest Rate Risk."

Restrictions in our credit facility may interrupt distributions to us from our subsidiaries, which may limit our ability to make distributions to you, satisfy our obligations and capitalize on business opportunities.

We are a holding company with no business operations. As such, we depend on the earnings and cash flow of our subsidiaries and the distribution of that cash to us in order to meet our obligations and to allow us to make distributions to our unitholders. Our credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens and engage in transactions with affiliates. Furthermore, our credit facility contains covenants requiring us to maintain a ratio of consolidated indebtedness to consolidated EBITDA of not more than 5.50 to 1.00 and a ratio of consolidated EBITDA to consolidated interest expense of not less than 2.25 to 1.00. If we fail to meet these tests or otherwise breach the terms of our credit facility our operating subsidiary will be prohibited from making any distribution to us and, ultimately, to you. Any interruption of distributions to us from our subsidiaries may limit our ability to satisfy our obligations and to make distributions to you. For more information regarding our credit facility, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations —Liquidity and Capital Resources."

Our acquisition strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow through acquisitions.

We continuously consider and enter into discussions regarding potential acquisitions. Any limitations on our access to capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire strategic and accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

Current weak economic conditions and the volatility and disruption in the weak financial markets have increased the cost of raising money in the debt and equity capital markets substantially while diminishing the availability of funds from those markets. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. These factors may impair our ability to execute our acquisition strategy.

In addition, we typically experience competitive bidding for the types of assets we contemplate purchasing. The weak economic conditions and competition for asset purchases could limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy could materially adversely affect our ability to maintain or pay higher distributions in the future.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment.

Our operations are subject to stringent and complex federal, state and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. For more information on our operations, see “Item 1. Business—Our Systems” for additional information on our operations. These laws include, for example, (1) the federal Clean Air Act and comparable state laws that impose obligations related to air emissions, (2) the federal Resource Conservation and Recovery Act (“RCRA”) and comparable state laws that impose requirements for the handling, storage, treatment or disposal of solid and hazardous waste from our facilities, (3) the federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (“CERCLA”) also known as “Superfund,” and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which our hazardous substances have been transported for disposal and (4) the Federal Water Pollution Control Act (the “Clean Water Act”) and comparable state laws that regulate discharges of wastewater from our facilities to state and federal waters. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations or imposing additional compliance requirements on such operations. Certain environmental laws, including CERCLA and analogous state laws, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or waste products into the environment.

There is inherent risk of incurring environmental costs and liabilities in connection with our operations due to our handling of natural gas and other petroleum products, air emissions and water discharges related to our operations and historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, natural resource and property damages and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our operational or compliance costs and the cost of any remediation that may become necessary. In particular, we may incur expenditures in order to attain or maintain compliance with legal requirements governing emissions of air pollutants from our facilities. We may not be able to recover all or any of these costs from insurance. For further information on environmental matters, see “Item 1. Business— Environmental, Health and Safety Matters” for additional information on environmental matters.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

The NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, on-going litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

While our natural gas gathering operations are generally exempt from FERC regulation under the NGA, our gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. FERC has recently issued a final rule (as amended by orders on rehearing, “Order 704”) requiring certain participants in the natural gas market, including intrastate pipelines, natural gas gatherers, natural gas marketers and natural gas processors, that engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. In addition, FERC has issued a final rule (“Order 720”) requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtus of gas over the previous three calendar years, to post daily certain information regarding the pipeline’s capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu per day.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of Targa's operations, see "Item 1. Business—Regulation of Operations".

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EP Act 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC as a natural gas companies under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject Targa to civil penalty liability. For more information regarding regulation of Targa's operations, see "Item 1. Business— Regulation of Operations".

Unexpected volume changes due to production variability or to gathering, plant or pipeline system disruptions may increase our exposure to commodity price movements.

Targa sells our processed natural gas to third parties and other Targa affiliates at our plant tailgates or at pipeline pooling points. Targa also manages the SAOU and LOU Systems' natural gas sales to third parties under contracts that remain in the name of the SAOU and LOU Systems. Sales made to natural gas marketers and end-users may be interrupted by disruptions to volumes anywhere along the system. Targa will attempt to balance sales with volumes supplied from our processing operations, but unexpected volume variations due to production variability or to gathering, plant or pipeline system disruptions may expose us to volume imbalances which, in conjunction with movements in commodity prices, could materially impact our income from operations and cash flow.

We may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspections, Protection, Enforcement and Safety Act of 2006, DOT, through the PHMSA, has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could do the most harm in "high consequence areas," including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing U.S. DOT regulations for intrastate gathering and transmission lines. We currently estimate that we will incur an aggregate cost of approximately $1.2 million between 2009 and 2011 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This estimate does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. At this time, we cannot predict the ultimate cost of compliance with this regulation, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. Following the initial round of testing and repairs, we will continue our pipeline integrity testing programs to assess and maintain the integrity or our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of our pipelines.

Our construction of new assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through the construction of new midstream assets. The construction of additions or modifications to our existing systems and the construction of new midstream assets, involve numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule or at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a new pipeline, the construction may occur over an extended period of time and we will not receive any material increases in revenues until the project is completed. Moreover, we may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we do not possess reserve expertise and we often do not have access to third party estimates of potential reserves in an area prior to constructing facilities in such area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to connect new natural gas supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

If we do not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with our asset base, our future growth will be limited.

Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors, then our future growth and ability to increase distributions will be limited.

Any acquisition involves potential risks, including, among other things:

- inaccurate assumptions about volumes, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- inaccurate assumptions about the overall costs of equity or debt;
- the diversion of management’s and employees’ attention from other business concerns;

· unforeseen difficulties operating in new product areas or new geographic areas; and

· customer or key employee losses at the acquired businesses.

If these risks materialize, the acquired assets may inhibit our growth or fail to deliver expected benefits.

Our acquisition strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our operations and cash flows available for distribution to our unitholders.

We do not have any officers or employees and rely solely on officers of our general partner and employees of Targa.

None of the officers of our general partner are employees of our general partner. We have entered into an Omnibus Agreement with Targa, pursuant to which Targa operates our assets and performs other administrative services for us such as accounting, legal, regulatory, corporate development, finance, land and engineering. Affiliates of Targa conduct businesses and activities of their own in which we have no economic interest, including businesses and activities relating to Targa. As a result, there could be material competition for the time and effort of the officers and employees who provide services to our general partner and Targa. If the officers of our general partner and the employees of Targa do not devote sufficient attention to the management and operation of our business, our financial results may suffer and our ability to make distributions to our unitholders may be reduced.

If our general partner fails to maintain an effective system of internal controls, then we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common units.

Targa Resources GP LLC, our general partner, has sole responsibility for conducting our business and for managing our operations. Effective internal controls are necessary for our general partner, on our behalf, to provide reliable financial reports, prevent fraud and operate us successfully as a public company. If our general partner's efforts to develop and maintain its internal controls are not successful, it is unable to maintain adequate controls over our financial processes and reporting in the future or it is unable to assist us in complying with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, our operating results could be harmed or we may fail to meet our reporting obligations. Ineffective internal controls also could cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

The amount of cash we have available for distribution to holders of our common units and subordinated units depends primarily on our cash flow and not solely on profitability. Consequently, even if we are profitable, we may not be able to make cash distributions to holders of our common units and subordinated units.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Terrorist attacks and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001 and the threat of future terrorist attacks on our industry in general and on us in particular, is not known at this time. However, resulting regulatory requirements and/or related business decisions associated with security are likely to increase our costs.

Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for our products and the possibility that infrastructure facilities could be direct targets of or indirect casualties of, an act of terror.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Risks Inherent in an Investment in Us

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

In order to make cash distributions at our current distribution rate of $0.5175 per common unit and subordinated unit per complete quarter or $2.07 per unit per year, we will require available cash of approximately $26.4 million per quarter or $105.4 million per year, based on common units and subordinated units outstanding as of December 31, 2008. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, levels of production of and demand for, natural gas and NGLs;
- the volume of natural gas we gather, treat, compress, process, transport and sell and the volume of NGLs we process or fractionate and sell;
- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- our ability to make borrowings under our credit facility to pay distributions;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;

- general and administrative expenses, including expenses we incur as a result of being a public company;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

Targa controls our general partner, which has sole responsibility for conducting our business and managing our operations. Targa has conflicts of interest with us and may favor its own interests to your detriment.

Targa owns and controls our general partner. Some of our general partner's directors and some of its executive officers, are directors or officers of Targa. Therefore, conflicts of interest may arise between Targa, including our general partner, on the one hand and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Targa to pursue a business strategy that favors us. Targa's directors and officers have a fiduciary duty to make decisions in the best interests of the owners of Targa, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as Targa or its owners, including Warburg Pincus, in resolving conflicts of interest; and
- Targa is not limited in its ability to compete with us and is under no obligation to offer assets to us.

The credit and business risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and business risk profiles of the general partner and its owners may be factors in credit evaluations of a master limited partnership. This is because the general partner can exercise significant influence over the business activities of the partnership, including its cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of the general partner and its owners, including the degree of their financial leverage and their dependence on cash flow from the partnership to service their indebtedness.

Targa, the owner of our general partner, has significant indebtedness outstanding and is partially dependent on the cash distributions from their indirect general partner and limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to our creditors. Our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or more risky than ours.

Our partnership agreement limits our general partner's fiduciary duties to holders of our units and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

The directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, Targa. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires and it has no duty or obligation to give any consideration to any interest of or factors affecting, us, our affiliates or any limited partner;
- provides that our general partner does not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner acting in good faith and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be “fair and reasonable” to us, as determined by our general partner in good faith and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;

- provides that our general partner and its officers and directors are not liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and nonappealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that in resolving conflicts of interest, it is presumed that in making its decision the general partner acted in good faith and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Targa is not limited in its ability to compete with us, which could limit our ability to acquire additional assets or businesses.

Neither our partnership agreement nor the Omnibus Agreement between us and Targa prohibits Targa from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Targa may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Targa is a large, established participant in the midstream energy business and has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with Targa with respect to commercial activities as well as for acquisition candidates. As a result, competition from Targa could adversely impact our results of operations and cash available for distribution.

Cost reimbursements due our general partner and its affiliates for services provided, which will be determined by our general partner, will be substantial and will reduce our cash available for distribution to you.

Pursuant to the Omnibus Agreement we entered into with Targa and Targa Resources GP LLC, our general partner, Targa receives reimbursement for the payment of operating expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services are substantial and reduce the amount of cash available for distribution to unitholders. See “Item 13. Certain Relationships and Related Transactions, and Director Independence.” In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify our general partner. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments on these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. Unitholders will not elect our general partner or our general partner’s board of directors and have no right to elect our general partner or our general partner’s board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by Targa. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Removal of our general partner without its consent will dilute and adversely affect our common unitholders.

If our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of the general partner because of the unitholder's dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

We may issue additional units without your approval, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

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

Affiliates of our general partner may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

Management of our general partner and Targa beneficially hold 292,252 common units and 11,528,231 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier. The sale of these units in the public markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or holders of our common units. This ability may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, at a time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution") and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner's incentive distribution rights.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity to make acquisitions, for expansion capital expenditures or for other purposes.

As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, for expansion capital expenditures or for other purposes.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

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

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

Our general partner has a limited call right that may require you to sell your units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. At the end of the subordination period, assuming no additional issuances of common units, our general partner and its affiliates will own approximately 24.5% of our aggregate outstanding common units.

Your liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in Louisiana and Texas. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute;

- or your right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service or IRS, were to treat us as a corporation or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to you would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. In order to maintain our status as a partnership for United States federal income tax purposes, 90% or more of our gross income in each tax year must be qualifying income under section 7704 of the Internal Revenue Code. We have not requested and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. We have requested a ruling from the IRS with respect to the qualifying nature of the income earned as a result of a purchase of our debt at a discount upon which, if granted, we may rely with respect to such income. There can be no assurance that the IRS will provide such a favorable ruling. However, any income earned as a result of a purchase or our debt at a discount plus any other non-qualifying income we earned in 2008 is less than 10% of our total gross income.

Although we do not believe based upon our current operations that we are treated as a corporation for federal income tax purposes, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35% and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, members of Congress have considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the legislation considered would not have appeared to affect our tax treatment, we are unable to predict whether any such change or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of any such tax on us by any other state will reduce the cash available for distribution to you.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

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

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely affected and the cost of any contest will reduce our cash available for distribution to you.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our unitholders are treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you may be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

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

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

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

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

We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations and may result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

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

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

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

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

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

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

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest are counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine in a timely manner that a termination occurred.

You may be subject to state and local taxes and return filing requirements in jurisdictions where you do not live as a result of investing in our common units.

In addition to federal income taxes, you may be subject to return filing requirements and other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, now or in the future, even if you do not live in any of those jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own assets and conduct business in the States of Texas and Louisiana. Currently, Texas does not impose a personal income tax on individuals. As we make acquisitions or expand our business, we may own assets or do business in states that impose a personal income tax. It is your responsibility to file all U.S. federal, state and local tax returns.

Item 1B. *Unresolved Staff Comments*

None

Item 2. ***Properties***

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

Our principal executive offices are located at 1000 Louisiana Street, Suite 4300, Houston, Texas 77002 and our telephone number is 713-584-1000.

Item 3. ***Legal Proceedings***

On December 8, 2005, WTG Gas Processing ("WTG") filed suit in the 333rd District Court of Harris County, Texas against several defendants, including Targa Resources, Inc. and three other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips Company ("ConocoPhillips") and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase the SAOU System from ConocoPhillips and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from Targa's competition to purchase the ConocoPhillips' assets and its successful acquisition of those assets in 2004. On October 2, 2007, the District Court granted defendants' motions for summary judgment on all of WTG's claims. WTG's motion to reconsider and for a new trial was overruled. On January 2, 2008, WTG filed a notice of appeal. On February 3, 2009, the parties presented oral arguments and the appeal is pending before the 14th Court of Appeals in Houston, Texas. We are contesting WTG's appeal, but can give no assurances regarding the outcome of the proceeding. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit.

We are not a party to any other legal proceedings other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. See "Item 1. Business—Regulation of Operations" and "Item 1. Business—Environmental Health and Safety Matters."

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

None

PART II

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

Market Information

Our common units have been listed on The NASDAQ Stock Market LLC ("NASDAQ") under the symbol "NGLS" since February 9, 2007. Prior to February 9, 2007, our equity securities were not listed on any exchange or traded on any public trading market. The following table sets forth the high and low sales prices of the common units, as reported by NASDAQ, as well as the amount of cash distributions declared for the period February 14, 2007 through December 31, 2008.

Quarter Ended	High	Low	Distribution per Common Unit	Distribution per Subordinated Unit
December 31, 2008	$ 17.11	$ 6.04	$ 0.51750	$ 0.51750
September 30, 2008	24.46	15.18	0.51750	0.51750
June 30, 2008	27.08	22.93	0.51250	0.51250
March 31, 2008	29.54	20.88	0.41750	0.41750
December 31, 2007	29.84	25.10	0.39750	0.39750
September 30, 2007	35.00	24.39	0.33750	0.33750
June 30, 2007	35.28	27.70	0.33750	0.33750
March 31, 2007	29.30	22.75	0.16875	0.16875

As of February 4, 2009, there were approximately 57 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. We have also issued 11,528,231 subordinated units, for which there is no established public trading market. The subordinated units are held by affiliates of Targa Resources GP LLC, our general partner. Our general partner and its affiliates will receive a quarterly distribution on these units only after sufficient funds have been paid to the common units. There is no established trading market for the 943,108 general partner units held by our general partner.

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our general partner.

Definition of Available Cash. The term "available cash," for any quarter, means all cash and cash equivalents on hand on the date of determination of available cash for that quarter less the amount of cash reserves established by our general partner to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distribution to our unitholders and to our general partner for any one or more of the next four quarters.

Minimum Quarterly Distribution. We intend to make cash distributions to the holders of common units and subordinated units on a quarterly basis in an amount equal to at least the minimum quarterly distribution of $0.3375 per unit or $1.35 per unit on an annualized basis, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. The board of directors of our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to our unitholders, reserves to reduce debt or, as necessary, reserves to comply with the term of any of our agreements or obligations. We will be prohibited from making any distributions to unitholders if it would cause an event of default or an event of default exists, under our credit agreement or indenture.

General Partner Interest. Our general partner is currently entitled to 2% of all quarterly distributions that we make prior to our liquidation. This general partner interest is represented by 943,108 general partner units. Our general partner has the right, but not the obligation, to contribute a proportional amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportional amount of capital to us to maintain its 2% general partner interest.

Incentive Distribution Rights. Our general partner also currently holds incentive distribution rights that entitle it to receive up to a maximum of 50% of the cash we distribute in excess of $0.5063 per unit per quarter. The maximum distribution of 50% includes distributions paid to our general partner on its general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on limited partner units that it owns.

Recent Sales of Unregistered Units

None

Repurchase of Equity by Targa Resources Partners LP

On October 10, 2008, the Board of Directors of our general partner approved a program for us to repurchase up to $50 million in value of our common units from time to time through December 31, 2009 in open market transactions, including block purchases or in privately negotiated transactions. The unit repurchase program authorizes us to make repurchases on a discretionary basis as determined by our management subject to market conditions, applicable legal requirements, available liquidity and other appropriate factors as determined by such officers. The unit repurchase program does not include specific price targets or timetables and may be modified or suspended at any time and could be terminated prior to completion. Repurchased common units will be cancelled and current payments on our incentive distribution rights will decrease.

There have been no repurchases of our common units under this program.

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

SELECTED FINANCIAL AND OPERATING DATA

Our historical results include the historical results of the SAOU and LOU Systems (acquired by Targa effective April 16, 2004) for 2008, 2007 and 2006; and the historical results of the North Texas System (acquired by Targa effective November 1, 2005) subsequent to October 31, 2005.

The information contained herein should be read together with and is qualified in its entirety by reference to, the historical combined financial statements and the accompanying notes included elsewhere in this Annual Report. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of factors that affect the comparability of the information reflected in the selected financial and operating data.

In the following tables, our predecessor entity comprises the net assets of the SAOU and LOU Systems as these were the first assets acquired by Targa on April 16, 2004. The financial and operating data as of and for the year ended December 31, 2004 are derived from the audited consolidated financial statements of Targa. Targa's consolidated financial results for 2004 includes the results of operations for the eight and a half month period commencing with its April 16, 2004 acquisition of the predecessor business from ConocoPhillips. The selected combined financial and operating data of the predecessor for the three and a half months ended April 15, 2004 are derived from the audited financial statements of the predecessor business.

The following table summarizes selected financial and operating data for the periods and as of the dates indicated.

	Targa Resources Partners LP					Predecessor
	Year Ended December 31,				March 12 (Inception) through December 31,	106-Day Period Ended April 15,
	2008	2007	2006	2005	2004	2004
	(In millions, except operating and price data)					
Statement of Operations data:						
Revenues	$2,074.1	$1,661.5	$1,738.5	$1,172.5	$602.6	$232.8
Costs and expenses:						
Product purchases	1,803.0	1,406.8	1,517.7	1,061.7	544.9	212.3
Operating expenses	55.3	50.9	49.1	24.4	15.3	7.9
Depreciation and amortization expense	74.3	71.8	69.9	23.1	10.4	3.8
General and administrative expense	22.4	18.9	16.1	16.7	11.1	0.8
Other	0.1	-	-	-	-	1.4
Gain on sale of assets	(0.1)	(0.3)	-	-	-	-
Total costs and expenses	1,955.0	1,548.1	1,652.8	1,125.9	581.7	226.2
Income from operations	119.1	113.4	85.7	46.6	20.9	6.6
Other income (expense):						
Interest expense, net	(38.3)	(22.0)	-	-	-	-
Interest expense, allocated from Parent	-	(19.4)	(88.0)	(21.2)	(6.1)	-
Gain on debt extinguishment	13.1	-	-	(3.7)	-	-
Gain (loss) related to derivatives	(1.0)	(30.2)	16.8	(12.0)	1.3	-
Income before income taxes	92.9	41.8	14.5	9.7	16.1	6.6
Deferred income tax expense (1)	(1.4)	(1.5)	(2.9)	-	-	(2.6)
Net income	$91.5	$40.3	$11.6	$9.7	$16.1	$4.0
Less:						
Net income attributable to predecessor operations	-	12.2				
Net income allocable to partners	91.5	28.1				
General partner interest in net income	7.0	0.6				
Net income available to common and subordinated unitholders	$84.5	$27.5				
Net income per limited partner unit - basic	$1.83	$0.81				
Net income per limited partner unit - diluted	$1.83	$0.81				
Cash distributions declared per unit	$1.97	$1.24				
Financial and Operating data:						
Financial data:						
Operating margin (2)	$215.8	$203.8	$171.7	$86.4	$42.4	$12.6
Adjusted EBITDA (3)	$228.9	$185.8	$154.1	$66.0	$31.3	$11.8
Distributable cash flow (4)	$152.8	$124.1	$57.5	$43.3	N/A	N/A
Operating data:						
Gathering throughput, MMcf/d (5)	445.8	452.0	433.8	302.4		
Plant natural gas inlet, MMcf/d (6)(7)	421.2	429.2	419.6	253.6		
Gross NGL production, MBbl/d	42.0	42.6	42.4	23.5		
Natural gas sales, BBtu/d (7)	415.6	410.2	489.4	259.3		
NGL sales, MBbl/d	37.3	36.4	36.0	22.0		
Condensate sales, MBbl/d	3.6	3.6	3.3	1.3		
Average realized prices (8):						
Natural gas, $/MMBtu	8.45	6.60	6.62	9.36		
NGL, $/gal	1.17	1.03	0.85	0.77		
Condensate, $/Bbl	82.52	65.63	59.87	58.96		

Balance Sheet Data (at year end):						
Property plant and equipment, net	$1,244.3	$1,259.6	$1,288.6	$1,325.9	$237.6	$266.0
Total assets	1,580.9	1,480.0	1,416.4	1,500.0	323.4	288.8
Long-term allocated debt, less current maturities	-	-	1,047.3	1,053.3	103.0	-
Long-term debt, less current maturities	696.8	626.3	-	-	-	-
Partners' capital/Net parent equity	762.4	614.2	245.9	281.2	139.2	170.9
Cash Flow Data:						
Net cash provided by (used in):				10.5	28.2	11.5
Operating activities	95.2	270.5	124.4	(6.8)	(2.9)	(1.2)
Investing activities	(51.0)	(40.7)	(32.9)	(3.7)	(25.4)	(10.3)
Financing activities	(13.5)	(178.8)	(91.5)	-	-	-

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(1) In May 2006, Texas adopted a margin tax consisting of a 1% tax on the amount by which total revenue exceeds cost of goods sold, as apportioned to Texas. The amount presented represents our estimated liability for this tax.

(2) Operating margin is total operating revenues less product purchases and operating expense. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—How We Evaluate Our Operations—Operating Margin" and "—Non-GAAP Financial Measures."

(3) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization and non-cash income or loss related to derivative instruments. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—How We Evaluate Our Operations—Adjusted EBITDA" and "—Non-GAAP Financial Measures."

(4) Distributable Cash Flow is net income plus depreciation and amortization and deferred taxes, adjusted for losses/(gains) on mark-to-market derivative contracts and early extinguishment of debt, less maintenance capital expenditures. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — How We Evaluate Our Operations — Distributable Cash Flow" and "— Non-GAAP Financial Measures."

(5) Gathering throughput represents the volume of natural gas gathered and passed through natural gas gathering pipelines from connections to producing wells and central delivery points.

(6) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(7) Plant inlet volumes include producer take-in-kind, while natural gas sales exclude producer take-in-kind volumes.

(8) Average realized prices include the impact of hedging activities.

Non-GAAP Financial Measures

Adjusted EBITDA. We define Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization and non-cash income or loss related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The economic substance behind management's use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

The generally accepted accounting principles ("GAAP") measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into management's decision-making processes.

	Targa Resources Partners LP					Predecessor
	Year Ended December 31,				March 12 (Inception) through December 31,	106-Day Period Ended April 15,
	2008	2007	2006	2005	2004	2004
	(In millions)					
Reconciliation of net cash provided by operating activities to Adjusted EBITDA:						
Net cash provided by operating activities	$95.2	$270.5	$124.4	$10.5	$28.2	$11.5
Allocated interest expense from parent (1)	-	18.5	81.8	16.5	5.2	-
Interest expense, net (1)	36.2	21.1	-	-	-	-
Gain on debt extinguishment	13.1	-	-	(3.7)	-	-
Early termination of commodity derivatives	87.4	-	-	-	-	-
Other	(0.5)	(0.1)	(0.4)	3.6	-	4.0
Changes in operating assets and liabilities which used (provided) cash:						
Accounts receivable and other assets	(64.3)	(88.8)	(80.9)	63.8	77.5	(25.1)
Accounts payable and other liabilities	61.8	(35.4)	29.2	(24.7)	(79.6)	21.4
Adjusted EBITDA	$228.9	$185.8	$154.1	$66.0	$31.3	$11.8
Reconciliation of net income to Adjusted EBITDA:						
Net income	$91.5	$40.3	$11.6	$9.7	$16.1	$4.0
Add:						
Allocated interest expense, net	-	19.4	88.0	21.2	6.1	-
Interest expense, net	38.3	22.0	-	-	-	-
Deferred income tax expense	1.4	1.5	2.9	-	-	2.6
Taxes other than income taxes	-	-	-	-	-	1.4
Depreciation and amortization expense	74.3	71.8	69.9	23.1	10.4	3.8
Non-cash (income) loss related to derivatives	23.4	30.8	(18.3)	12.0	(1.3)	-
Adjusted EBITDA	$228.9	$185.8	$154.1	$66.0	$31.3	$11.8

(1) Net of amortization of debt issuance costs of $2.1 million, $1.8 million and $6.2 million for 2008, 2007 and 2006.

Operating Margin. We define operating margin as total operating revenues, which consist of natural gas and NGL sales plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases and operating expense. Management reviews operating margin monthly for consistency and trend analysis. Based on this monthly analysis, management takes appropriate action to maintain positive trends or to reverse negative trends. Management uses operating margin as an important performance measure of the core profitability of our operations.

The GAAP measure most directly comparable to operating margin is net income. Our non-GAAP financial measure of operating margin should not be considered as an alternative to GAAP net income. Operating margin is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because operating margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing its utility. Management compensates for the limitations of operating margin as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into management's decision-making processes.

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Operating margin provides useful information to investors because it is used as a supplemental financial measure by our management and by external users of our financial statements, including such investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

	Targa Resources Partners LP					Predecessor
	Year Ended December 31,				March 12 (Inception) through December 31,	106-Day Period Ended April 15,
	2008	2007	2006	2005	2004	2004
	(In millions)					
Reconciliation of net income to operating margin:						
Net income	$91.5	$40.3	$11.6	$9.7	$16.1	$4.0
Add:						
Depreciation and amortization expense	74.3	71.8	69.9	23.1	10.4	3.8
Deferred income tax expense	1.4	1.5	2.9	-	-	2.6
Allocated interest expense, net	-	19.4	88.0	21.2	6.1	-
Interest expense, net	38.3	22.0	-	-	-	-
Gain on debt extinguishment	(13.1)	-	-	3.7	-	-
(Gain) loss on mark-to-market derivatives	1.0	30.2	(16.8)	12.0	(1.3)	-
General and administrative and other expense	22.4	18.6	16.1	16.7	11.1	2.2
Operating margin (1)	$215.8	$203.8	$171.7	$86.4	$42.4	$12.6

(1) Includes non-cash charges related to commodity hedges of $1.0 million, $30.2 million and $(16.8) million for 2008, 2007and 2006.

Distributable Cash Flow. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by the board of directors of our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important non-GAAP financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

The economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to make distributions to our investors.

The GAAP measure most directly comparable to distributable cash flow is net income. Our non-GAAP measure of distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be compatible to similarly titled measures of other companies, thereby diminishing its utility.

We compensate for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into our decision making processes.

	Year Ended December 31,			
	2008	**2007**	**2006**	**2005**
Reconciliation of net income to "distributable cash flow":	**(In millions)**			
Net income	$ 91.5	$ 40.3	$ 11.6	$ 9.7
Depreciation and amortization expense	74.3	71.8	69.9	23.1
Deferred income tax expense	1.4	1.5	2.9	-
Amortization in interest expense	2.1	1.8	6.2	4.7
Gain on debt extinguishment	(13.1)	-	-	-
Non-cash (gain) loss related to derivatives	23.4	30.2	(16.8)	12.0
Maintenance capital expenditures	(26.7)	(21.5)	(16.3)	(6.2)
Distributable cash flow (1)	$ 152.9	$ 124.1	$ 57.5	$ 43.3

(1) Distributable cash flow for 2007, 2006 and 2005 reflect allocated interest from parent of $19.4 million, $88.0 million and $21.2 million.

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

On February 14, 2007, Targa contributed its ownership interests in the North Texas System to us. On October 24, 2007, we acquired Targa's ownership interests in the SAOU System and the LOU System. As required by Statement of Financial Accounting Standards ("SFAS") 141, we accounted for these transactions as transfers of net assets between entities under common control. For combinations of entities under common control, the purchase cost provisions (as they relate to purchase business combinations involving unrelated entities) of SFAS 141 explicitly do not apply; instead the method of accounting prescribed by SFAS 141 for such transfers is similar to the pooling-of-interests method of accounting. Under this method, the carrying amount of net assets recognized in the balance sheets of each combining entity are carried forward to the balance sheet of the combined entity and no other assets or liabilities are recognized as a result of the combination (that is, no recognition is made for a purchase premium or discount representing any difference between the cash consideration paid and the book value of the net assets acquired).

In connection with our IPO, the North Texas System was presented as our predecessor entity. As a result of our October 2007 acquisition of the SAOU and LOU Systems, the predecessor entity for us is now considered to be the net assets of the SAOU and LOU Systems as these were the first assets acquired by Targa on April 16, 2004. Therefore, subsequent to the contribution of the North Texas System from Targa on February 14, 2007, we recognized the assets and liabilities of the North Texas System contributed to us at their carrying amounts (historical cost) in the accounts of the SAOU and LOU Systems (the predecessor entity) at the date of transfer. The accounting treatment for combinations of entities under common control is consistent with the concept of poolings as combinations of common shareholder (or unitholder) interests.

In addition to requiring that assets and liabilities be carried forward at historical costs, SFAS 141 also prescribes that for transfers of net assets between entities under common control, all income statements presented be combined as of the date of common control. Accordingly, our historical results include the historical results of the SAOU and LOU Systems (acquired by Targa effective April 16, 2004) for 2008, 2007 and 2006; and the historical results of the North Texas System (acquired by Targa effective November 1, 2005) subsequent to October 31, 2005.

The following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our historical financial statements and notes included elsewhere in this Annual Report.

Overview

We are a Delaware limited partnership formed by Targa to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are engaged in the business of gathering, compressing, treating, processing and selling natural gas and fractionating and selling NGLs and NGL products. We currently operate in the Fort Worth Basin in North Texas, the Permian Basin in West Texas and in Southwest Louisiana.

We are owned 98% by our limited partners and 2% by our general partner, Targa Resources GP LLC, an indirect, wholly-owned subsidiary of Targa. Our limited partner common units are publicly traded on the NASDAQ Stock Market LLC under the symbol "NGLS."

Factors That Significantly Affect Our Results

Our results of operations are substantially impacted by changes in commodity prices as well as increases and decreases in the volume of natural gas that we gather, which we refer to as throughput volume. Throughput volumes and capacity utilization rates generally are driven by wellhead production, our competitive position on a regional basis and more broadly by prices and demand for natural gas and NGLs.

Contract Mix. Our processing contract arrangements can have a significant impact on our profitability. We generate revenue based on the contractual arrangements we have with our producer customers. These arrangements can be in many forms which vary in the amount of commodity price risk they carry. Substantially all of our revenues are generated under percent-of-proceeds arrangements pursuant to which we receive a portion of the natural gas and/or NGLs as payment for services. Below is a table summarizing our average contract mix for 2008, including the potential impacts of changes in commodity prices on operating margins:

Contract Type	Percent of Throughput	Impact of Commodity Prices
Percent-of-Proceeds	77%	Decreases in natural gas and/or NGL prices generate decreases in operating margin.
Wellhead Purchases/Keep Whole	20%	Increases in natural gas prices relative to NGL prices generate decreases in operating margin. Decreases in NGL prices relative to natural gas prices generate decreases in operating margin.
Hybrid	1%	In periods of favorable processing economics, similar to percent-of-proceeds (or wellhead purchases/keep-whole in some circumstances, if economically advantageous to the processor). In periods of unfavorable processing economics, similar to fee-based.
Fee Based	2%	No direct impact from commodity price movements.

Actual contract terms are based upon a variety of factors, including natural gas quality, geographic location and the competitive commodity and pricing environment at the time the contract is executed and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to natural gas and NGL prices, may change as a result of producer preferences, competition and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common as well as other market factors. We prefer to enter into contracts with less commodity price sensitivity, including fee-based and percent-of-proceeds arrangements.

We attempt to mitigate the price risk associated with our contract mix through hedging activities which can materially impact our results of operations. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Impact of Our Hedging Activities. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas, NGLs and condensate equity volumes for the years 2009 through 2012 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for this period. For additional information regarding our hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

General and Administrative Expenses. Prior to the contribution of the assets of the North Texas System to us and the acquisition of the assets from the SAOU and LOU Systems by us from Targa, general and administrative expenses were allocated from Targa to the North Texas, SAOU and LOU Systems in accordance with the general and administrative expenses allocation policies of Targa. On February 14, 2007, we entered into an omnibus agreement with Targa, pursuant to which our allocated general and administrative expenses related to the North Texas System were capped at $5.0 million per year for three years, subject to adjustment.

On October 24, 2007, we amended and restated our omnibus agreement with Targa (the "Omnibus Agreement"). The Omnibus Agreement governs certain relationships between Targa and us, including:

- Targa's obligation to provide certain general and administrative services to us;

- our obligation to reimburse Targa and its affiliates for the provision of general and administrative services (a) subject to a cap of $5 million (relating solely to the North Texas System) in the first year, with increases in the subsequent two years based on a formula specified in the Omnibus Agreement and (b) fully allocated as to the SAOU and LOU Systems according to Targa's previously established allocation practices;

- our obligation to reimburse Targa and its affiliates for direct expenses incurred on our behalf; and

- Targa's obligation to indemnify us for certain liabilities and our obligation to indemnify Targa for certain liabilities.

Allocated general and administrative expenses were $18.2 million, $15.6 million and $16.1 million for 2008, 2007 and 2006. For a more complete description of this agreement, see "Item 13. Certain Relationships and Related Transactions, and Director Independence—Omnibus Agreement."

In addition to these allocated general and administrative expenses, we incur incremental general and administrative expenses as a result of operating as a separate publicly held limited partnership. These direct, incremental general and administrative expenses, which were approximately $4.2 million and $3.3 million during 2008 and 2007, including one-time expenses associated with our equity offerings, financing arrangements and acquisitions were not subject to the cap contained in the Omnibus Agreement. These costs include costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, registrar and transfer agent fees and independent director compensation. These incremental general and administrative expenditures are not reflected in the historical financial statements of the North Texas, SAOU and LOU Systems.

The historical financial statements of the SAOU and LOU Systems and the North Texas System include certain items that will not impact our future results of operations and liquidity including the items described below:

Affiliate Indebtedness and Borrowings. Affiliate indebtedness prior to our acquisition of the SAOU and LOU Systems and the contribution of the North Texas System, consisted of borrowings incurred by Targa and allocated to us for financial reporting purposes.

Prior to Targa's acquisition of Dynegy's interest in Dynegy Midstream Services, Limited Partnership (the "DMS Acquisition"), which included the North Texas System, the Predecessor Business was financed through borrowings by Targa and reflected allocated indebtedness on its balance sheet and allocated interest expense on its income statement. A substantial portion of the DMS Acquisition was also financed through borrowings by Targa. Following the October 31, 2005 DMS Acquisition, a significant portion of Targa's acquisition borrowings were allocated to the North Texas System, resulting in approximately $870.1 million of allocated indebtedness and corresponding levels of interest expense. This indebtedness was incurred by Targa in connection with the DMS Acquisition and the entity holding the North Texas System provided a guarantee of this indebtedness. This indebtedness was also secured by a collateral interest in both the equity of the entity holding the North Texas System as well as its assets. In connection with our IPO, this guarantee was terminated, the collateral interest was released and the allocated indebtedness was retired.

On February 14, 2007, we borrowed approximately $294.5 million under our credit facility. The proceeds from this borrowing, together with approximately $371.2 million of net proceeds from our IPO (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units), were used to repay approximately $665.7 million of affiliate indebtedness and the remaining balance of this indebtedness was retired and treated as a capital contribution to us.

On October 24, 2007, we completed our acquisition of the SAOU and LOU Systems concurrently with the sale of 13,500,000 common units representing limited partnership interests in us for gross proceeds of $362.7 million (approximately $349.2 million after underwriting discount and structuring fees). The net proceeds from the sale of the 13,500,000 units were used to pay approximately $2.5 million in expenses associated with the sale of the common units and $24.2 million to Targa for certain hedge transactions associated with the SAOU and LOU Systems. We used the net proceeds after offering expenses and the hedge transactions of $322.5 million along with net borrowings of $375.5 million to pay approximately $698.0 million of the acquisition costs of the SAOU and LOU Systems. The allocated indebtedness from Targa related to the SAOU and LOU Systems was $124.0 million. Targa debt was guaranteed by the entities that own the SAOU and LOU Systems and was secured by a collateral interest in both the equity interests of those entities as well as their underlying assets. In conjunction with our acquisition of the SAOU and LOU Systems, this guarantee was terminated, the collateral interest was released and the allocated indebtedness was retired.

Working Capital Adjustments. Prior to our IPO and the contribution of the North Texas System in February 2007 and the acquisition of the SAOU and LOU Systems in October 2007, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with the Predecessor Business' respective parent, but were recorded as an adjustment to parent equity on the balance sheet. The primary intercompany transactions between the respective parent and the Predecessor Business are natural gas and NGL sales, the provision of operations and maintenance activities and the provision of general and administrative services. Accordingly, the working capital of the Predecessor Business does not reflect any affiliate accounts receivable for intercompany commodity sales or affiliate accounts payable for the personnel and services provided or paid for by the applicable parent on behalf of the Predecessor Business.

Distributions to our Unitholders.

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs. Historically, we have relied on internally generated cash flows for these purposes. Due to the timing of our IPO, a pro-rated distribution for the first quarter of 2007 of $0.16875 per common and subordinated unit was paid.

The following table shows the distributions we declared for the period February 14, 2007 through December 31, 2008.

		Distributions Paid					Distributions per limited partner unit
		Common	Subordinated	General Partner			
Date Declared	Date Paid	Units	Units	Incentive	2%	Total	
		(In thousands, except per unit amounts)					
October 24, 2008	November 14, 2008	$ 17,934	$ 5,966	$ 1,931	$ 527	$ 26,358	$ 0.51750
July 23, 2008	August 14, 2008	17,759	5,908	1,711	518	25,896	0.51250
April 23, 2008	May 15, 2008	14,467	4,813	208	398	19,886	0.41750
January 23, 2008	February 14, 2008	13,768	4,582	66	376	18,792	0.39750
October 24, 2007	November 14, 2007	11,082	3,891	-	305	15,278	0.33750
July 24, 2007	August 14, 2007	6,526	3,890	-	212	10,628	0.33750
April 23, 2007	May 15, 2007	3,263	1,945	-	107	5,315	0.16875

On January 23, 2009, we declared a cash distribution of $0.5175 per unit on our outstanding common and subordinated units. The distribution was paid on February 13, 2009 to unitholders of record on February 4, 2008, for the period October 1, 2008 through December 31, 2008. The total distribution paid was approximately $26.4 million, with approximately $23.9 million paid to our common unitholders and $0.5 million and $1.9 million paid to our general partner for its general partner and incentive distribution interests.

General Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Natural Gas Supply and Outlook. Fluctuations in energy prices can affect production rates and investments by third parties in the development of new natural gas reserves. Generally, drilling and production activity will increase as natural gas prices increase and decrease as natural gas prices decrease. The recent substantial decline in natural gas prices has led many exploration and production companies to reduce planned capital expenditures for drilling and production activities during 2009 which could lead to a decrease in the level of natural gas production in our areas of operation.

Commodity Prices. Our operating income generally improves in an environment of higher natural gas, NGL and condensate prices, primarily as a result of our percent-of-proceeds contracts. Our processing profitability is largely dependent upon pricing and market demand for natural gas, NGLs and condensate, which are beyond our control and have been volatile. Due to the recent volatility, we are uncertain of what pricing and market demand for natural gas, NGLs and condensate will be throughout 2009. The current weak economic conditions have negatively affected the pricing and market demand for natural gas, NGLs and condensate, which has caused a reduction in the profitability of our processing operations. In a declining commodity price environment, without taking into account our hedges, we will realize a reduction in cash flows under our percent-of-proceeds contracts proportionate to average price declines. We have attempted to mitigate our exposure to commodity price movements by entering into hedging arrangements. For additional information regarding our hedging activities, see "—Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Volatile Capital Markets. We are dependent on our ability to access the equity and debt capital markets in order to fund acquisitions and expansion expenditures. Global financial markets have been and are expected to continue to be, extremely volatile and disrupted and the current weak economic conditions have recently caused a significant decline in commodity prices. As a result, we may be unable to raise equity or debt capital on satisfactory terms or at all, which may negatively impact the timing and extent to which we execute growth plans. Prolonged periods of low commodity prices or volatile capital markets may impact our ability or willingness to enter into new hedges, fund organic growth, connect to new supplies of natural gas, execute acquisitions or implement expansion capital expenditures.

Our Operations

Our results of operations are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, moved and sold through our gathering, processing and pipeline systems; the volumes of NGLs and residue natural gas sold; and the level of natural gas and NGL prices. We generate our revenues and our operating margins principally under percent-of-proceeds contractual arrangements. Under these arrangements, we generally gather natural gas from producers at the wellhead or central delivery points, move the wellhead natural gas through our gathering system, treat and process the natural gas and then sell the resulting residue natural gas and NGLs at published index market prices. We remit to the producers either an agreed upon percentage of recovered volumes or the actual proceeds that we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage of the proceeds based on index related prices for the natural gas and NGLs. Under these types of arrangements, our revenues correlate directly with the price of natural gas and NGLs. During 2008, our percent-of-proceeds activities accounted for approximately 77% of our natural gas throughput volumes. The balance of our throughput volumes are processed under wellhead purchase contracts, keep-whole contracts, fee based contracts and hybrid contractual arrangements.

We sell the majority of our processed natural gas, NGLs and high pressure condensate to Targa at market-based rates pursuant to natural gas, NGL and condensate purchase agreements. Low-pressure condensate is sold to third parties. See "Item 13. Certain Relationships and Related Transactions and Director Independence."

How We Evaluate Our Operations

Our profitability is a function of the difference between the revenues we receive from our operations, including revenues from the natural gas, NGLs and condensate we sell and the costs associated with conducting our operations, including the costs of wellhead natural gas that we purchase as well as operating and general and administrative costs. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Our contract portfolio, the prevailing pricing environment for natural gas and NGLs and the natural gas and NGL throughput on our system are important factors in determining our profitability. Our profitability is also affected by the NGL content in gathered wellhead natural gas, demand for our products and changes in our customer mix.

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include the following: (1) throughput volumes, (2) facility efficiencies and fuel consumption, (3) operating margin, (4) operating expenses, (5) Adjusted EBITDA and (6) distributable cash flow.

Throughput Volumes, Facility Efficiencies and Fuel Consumption. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our systems. This is achieved by connecting new wells, through additional volumes at existing central delivery points, as well as by capturing supplies currently gathered by third parties.

In addition, we seek to increase operating margins by limiting volume losses and reducing fuel consumption by increasing compression efficiency. With our gathering systems' extensive use of remote monitoring capabilities, we monitor the volumes of natural gas received at the wellhead or central delivery points along our gathering systems, the volume of natural gas received at our processing plant inlets and the volumes of NGLs and residue natural gas recovered by our processing plants. This information is tracked through our processing plants to determine customer settlements and helps us increase efficiency and reduce fuel consumption.

As part of monitoring the efficiency of our operations, we measure the difference between the volume of natural gas received at the wellhead or central delivery points on our gathering systems and the volume received at the inlet of our processing plants as an indicator of fuel consumption and line loss. We also track the difference between the volume of natural gas received at the inlet of the processing plant and the NGLs and residue gas produced at the outlet of such plants to monitor the fuel consumption and recoveries of the facilities. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis.

Operating Margin. We review performance based on the non-generally accepted accounting principle ("non-GAAP") financial measure of operating margin. We define operating margin as total operating revenues, which consist of natural gas and NGL sales plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases and operating expense. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges. Our operating margin is impacted by volumes and commodity prices as well as by our contract mix and hedging program, which are described in more detail below. We view our operating margin as an important performance measure of the core profitability of our operations. We review our operating margin monthly for consistency and trend analysis.

The GAAP measure most directly comparable to operating margin is net income. Our non-GAAP financial measure of operating margin should not be considered as an alternative to GAAP net income. Operating margin is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because operating margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

We compensate for the limitations of operating margin as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into our decision-making processes.

	2008	2007	2006
		(In millions)	
Reconciliation of net income to operating margin:			
Net income	$ 91.5	$ 40.3	$ 11.6
Add:			
Depreciation and amortization expense	74.3	71.8	69.9
Deferred income tax expense	1.4	1.5	2.9
Allocated interest expense, net	-	19.4	88.0
Interest expense, net	38.3	22.0	-
Gain on extinguishment of debt	(13.1)	-	-
(Gain) loss related to derivatives	1.0	30.2	(16.8)
General and administrative and other expense	22.4	18.6	16.1
Operating margin (1)	$ 215.8	$ 203.8	$ 171.7

(1) Includes non-cash charges related to commodity hedges of $1.0 million, $30.2 million and $(16.8) million for 2008, 2007 and 2006.

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Operating margin provides useful information to investors because it is used as a supplemental financial measure by us and by external users of our financial statements, including such investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

See “Item 6. Selected Consolidated Financial and Operating Data—Non-GAAP Financial Measures.”

Operating Expenses. Operating expenses are costs associated with the operation of a specific asset. Direct labor, ad valorem taxes, repair and maintenance, utilities and contract services compose the most significant portion of our operating expenses. These expenses generally remain relatively stable independent of the volumes through our systems but fluctuate depending on the scope of the activities performed during a specific period.

Adjusted EBITDA. Adjusted EBITDA is another non-GAAP financial measure that is used by us. We define Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization and non-cash income or loss related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income. Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider Adjusted EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA excludes some, but not all, items that affect net income and net cash provided by operating activities and is defined differently by different companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

We compensate for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into our decision-making processes.

	Year Ended December 31,		
	2008	2007	2006
		(In millions)	
Reconciliation of net cash provided by operating activities to Adjusted EBITDA:			
Net cash provided by operating activities	$ 95.2	$ 270.5	$ 124.4
Allocated interest expense from parent (1)	-	18.5	81.8
Interest expense, net (2)	36.2	21.1	-
Gain on debt extinguishment	13.1	-	-
Early termination of commodity derivatives	87.4	-	-
Other	(0.5)	(0.1)	(0.4)
Changes in operating working capital which used (provided) cash:			
Accounts receivable and other assets	(64.3)	(88.8)	(80.9)
Accounts payable and other liabilities	61.8	(35.4)	29.2
Adjusted EBITDA	$ 228.9	$ 185.8	$ 154.1
Reconciliation of net income to Adjusted EBITDA:			
Net income	$ 91.5	$ 40.3	$ 11.6
Add:			
Allocated interest expense, net	-	19.4	88.0
Interest expense, net	38.3	22.0	-
Deferred income tax expense	1.4	1.5	2.9
Depreciation and amortization expense	74.3	71.8	69.9
Non-cash (income) loss related to derivatives	23.4	30.8	(18.3)
Adjusted EBITDA	$ 228.9	$ 185.8	$ 154.1

(1) Net of amortization of debt issuance costs of $6.2 million for 2006.
(2) Net of amortization of debt issuance costs of $2.1 million and $1.8 million for 2008 and 2007.

Distributable Cash Flow. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by the board of directors of our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions. Distributable cash flow is also an important non-GAAP financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit’s yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

The economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to make distributions to our investors.

The GAAP measure most directly comparable to distributable cash flow is net income. Our non-GAAP measure of distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be compatible to similarly titled measures of other companies, thereby diminishing its utility.

We compensate for the limitations of distributable cash flow as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into our decision making processes.

Reconciliation of "Distributable Cash Flow" to Net Income

	Year Ended December 31,		
	2008	2007	2006
Reconciliation of net income to "distributable cash flow":		(In millions)	
Net income	$ 91.5	$ 40.3	$ 11.6
Depreciation and amortization expense	74.3	71.8	69.9
Deferred income tax expense	1.4	1.5	2.9
Amortization in interest expense	2.1	1.8	6.2
Gain on debt extinguishment	(13.1)	-	-
Non-cash (gain) loss related to derivatives	23.4	30.2	(16.8)
Maintenance capital expenditures	(26.7)	(21.5)	(16.3)
Distributable cash flow (1)	$ 152.9	$ 124.1	$ 57.5

(1) Distributable cash flow for 2007 and 2006 reflect allocated interest from parent of $19.4 million and $88.0 million.

Below is a reconciliation of net income as reported and distributable cash flow to which unit holders are entitled which excludes the results of operations of the North Texas System and the SAOU and LOU Systems prior to their ownership by the Partnership.

	For the Year Ended December 31, 2007			
		Pre-Acquistion		
	TRP LP	North Texas Jan 1, 2007 to Feb 13, 2007	SAOU/LOU Jan 1, 2007 to Oct 23, 2007	Post Acquisition TRP
			(in millions)	
Reconciliation of "Distributable cash flow" to net income:				
Net income (loss)	$ 40.3	$ (6.9)	$ 19.1	$ 28.1
Depreciation and amortization expense	71.8	6.9	11.7	53.2
Deferred income tax expense	1.5	-	-	1.5
Amortization of debt issue costs	1.8	-	0.9	0.9
Loss(gain) on mark-to-market derivative contracts	30.2	-	30.2	-
Maintenance capital expenditures	(21.5)	(1.5)	(5.9)	(14.1)
Distributable cash flow (a)	$ 124.1	$ (1.5)	$ 56.0	$ 69.6

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management 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. The policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements, because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain.

Revenue Recognition. Our primary types of sales and service activities reported as operating revenues include:

- sales of natural gas, NGLs and condensate; and

- natural gas processing, from which we generate revenues through the compression, gathering, treating and processing of natural gas.

We recognize revenues when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, if applicable, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectibility is reasonably assured.

For processing services, we receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, we receive either an agreed upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage based on index related prices for the natural gas and NGLs. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, we keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. Natural gas or NGLs that we receive for services or purchases for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee-based contracts, we receive a fee based on throughput volumes.

We generally report revenues gross in the consolidated statements of operations. Except for fee-based contracts, we act as the principal in the transactions where we receive commodities, take title to the natural gas and NGL and incur the risks and rewards of ownership.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues and operating and general and administrative costs (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing tangible and intangible assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from estimated amounts.

Property, Plant and Equipment. Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The estimated service lives of our functional asset groups are as follows:

Asset Group	Range of Years
Gas gathering systems and processing systems	15 to 25
Other property and equipment	3 to 7

Expenditures for maintenance and repairs are expensed as incurred. Expenditures to refurbish assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Upon disposition or retirement of property, plant and equipment, any gain or loss is charged to operations.

Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities the extent and frequency of maintenance programs. From time to time, we utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We may capitalize certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs. Upon disposition or retirement of property, plant and equipment, any gain or loss is charged to operations.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses and the market and business environments to identify indicators that may suggest an asset may not be recoverable.

We evaluate an asset for recoverability by comparing the carrying value of the asset with the asset's expected future undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. We recognize an impairment loss when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our Consolidated Statements of Operations.

Price Risk Management (Hedging). All derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If a derivative qualifies for hedge accounting and is designated as a hedge, the effective portion of the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income ("OCI"), a component of partners' capital and reclassified to earnings when the forecasted transaction occurs. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument becomes ineffective. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. At the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Hedge effectiveness is measured on a quarterly basis. Any ineffective portion of the unrealized gain or loss is reclassified to earnings in the current period.

Estimated Useful Lives. The estimated useful lives of our long-lived assets are used to compute depreciation expense, future asset retirement obligations and in impairment testing. Estimated useful lives are based, among other things, on the assumption that we provide an appropriate level of maintenance capital expenditures while the assets are still in operation. Without these continued capital expenditures, the useful lives of these assets could decrease significantly. Estimated lives could be impacted by such factors as future energy prices, environmental regulations, various legal factors and competition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future asset retirement obligations may be insufficient and impairments in carrying values of tangible and intangible assets may result.

Accounting Pronouncements Recently Adopted

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS 157, "Fair Value Measurements." SFAS 157 establishes a framework for measuring fair value and expands disclosures about fair value measurements. The FASB partially deferred the effective date of SFAS 157 for nonfinancial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. We adopted SFAS 157 with respect to financial assets and liabilities that are recognized on a recurring basis on January 1, 2008. Although the adoption of SFAS 157 did not materially impact our financial condition, results of operations or cash flow, we are now required to provide additional disclosures as part of our financial statements.

SFAS 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. For further discussion and disclosure of SFAS 157 requirements, see Note 13 to our Consolidated Financial Statements beginning on page F-1 of this Annual Report.

In February 2007, the FASB issued SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115." SFAS 159 expands opportunities to use fair value measurements in financial reporting and permits entities to choose to measure many financial instruments and certain other items at fair value. Our adoption of SFAS 159 on January 1, 2008 did not have a material impact on our consolidated financial statements.

In March 2008, the FASB issued SFAS 161, *"Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133."* SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133, *"Derivative Instruments and Hedging Activities*" and its related interpretations and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Early adoption is encouraged. Our adoption of SFAS 161 as of December 31, 2008 did not impact our consolidated financial position, results of operations or cash flows. The additional disclosures required by SFAS 161 are included in Note 9 to Consolidated Financial Statements, which begins on page F-1.

Accounting Pronouncements Recently Issued

In March 2008, the FASB's Emerging Issues Task Force ("EITF") reached a consensus on EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships." EITF 07-4 improves the comparability of earnings per unit calculations for master limited partnerships ("MLPs") with incentive distribution rights ("IDRs") in accordance with Statement 128 and its related interpretations. Under EITF 07-4, when an MLP's current-period earnings are in excess of cash distributions and the IDRs are a separate limited partner interest, undistributed earnings should be allocated to the general partner ("GP"), limited partners ("LPs") and IDR holder utilizing the contractual terms of the partnership agreement. The distribution formula for available cash specified in the partnership agreement contractually mandates the way in which earnings are distributed.

Additionally, EITF 07-4 requires an MLP to reflect its contractual obligation to make distributions as of the end of the current reporting period. Therefore, an MLP would reduce (increase) income (loss) from continuing operations (or net income or loss) for the current reporting period by the amount of available cash that has been or will be distributed to the GP, LPs and IDR holder for that current reporting period. If distributions to the IDR holder are contractually limited to available cash as defined in the partnership agreement, then the specified threshold for the current reporting period would be the holder's share of available cash that has been or will be distributed to the IDR holder for that current reporting period.

EITF 07-4 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and interim periods within those fiscal years. Earlier application is not permitted. Our adoption of EITF 07-4 will not impact our consolidated financial position, results of operations or cash flows. We are currently evaluating the effect this pronouncement will have on our present computation of earnings per unit.

Results of Operations

Our results of operations for the years ended December 31, 2008, 2007 and 2006 are presented and evaluated on a combined basis, combining our results with the results of operations reflected in the audited historical financial statements of the SAOU and LOU Systems prior to October 24, 2007, with the operations of the North Texas System prior to February 14, 2007.

The following table summarizes our combined results of operations for the periods and as of the dates indicated.

	Year Ended December 31,		
	2008	2007	2006
	(In millions, except operating and price data)		
Revenues	$ 2,074.1	$ 1,661.5	$ 1,738.5
Product purchases	1,803.0	1,406.8	1,517.7
Operating expenses	55.3	50.9	49.1
Depreciation and amortization expense	74.3	71.8	69.9
General and administrative expense	22.4	18.9	16.1
Other	0.1	-	-
Gain on sale of assets	(0.1)	(0.3)	-
Income from operations	119.1	113.4	85.7
Interest expense, net	(38.3)	(22.0)	-
Interest expense allocated from Parent	-	(19.4)	(88.0)
Gain on extinguishment of debt	13.1	-	-
(Gain) loss on mark-to-market derivative instruments	(1.0)	(30.2)	16.8
Deferred income tax expense (1)	(1.4)	(1.5)	(2.9)
Net income	$ 91.5	$ 40.3	$ 11.6
Less:			
Net income attributable to predecessor operations	-	12.2	
Net income allocable to partners	91.5	28.1	
General partner interest in net income	7.0	0.6	
Net income available to common and subordinated unitholders	$ 84.5	$ 27.5	
Net income per limited partner unit -basic	$ 1.83	$ 0.81	
Net income per limited partner unit -diluted	$ 1.83	$ 0.81	
Cash distributions declared per unit	$ 1.97	$ 1.24	
Financial and Operating data:			
Financial data:			
Operating margin (2)	$ 215.8	$ 203.8	$ 171.7
Adjusted EBITDA (3)	228.9	185.8	154.1
Distributable cash flow (4)	152.8	124.1	57.5
Operating data:			
Gathering throughput, MMcf/d (5)	445.8	452.0	433.8
Plant natural gas inlet, MMcf/d (6)(7)	421.2	429.2	419.6
Gross NGL production, MBbl/d	42.0	42.6	42.4
Natural gas sales, BBtu/d (7)	415.6	410.2	489.4
NGL sales, MBbl/d	37.3	36.4	36.0
Condensate sales, MBbl/d	3.6	3.6	3.3
Average realized prices:			
Natural Gas, $/MMBtu	8.45	6.60	6.62
NGL, $/gal	1.17	1.03	0.85
Condensate, $/ Bbl	82.52	65.63	59.87

(1) In May 2006, Texas adopted a margin tax, consisting of a 1% tax on the amount by which total revenue exceeds cost of goods sold, as apportioned to Texas. The amount presented represents our estimated liability for this tax.

(2) Operating margin is total operating revenues less product purchases and operating expense. See "—How We Evaluate Our Operations—Operating Margin" and "Selected Consolidated Financial and Operating Data—Non-GAAP Financial Measures."

(3) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization and non-cash income or loss related to derivative instruments. See "—How We Evaluate Our Operations—Adjusted EBITDA" and "Selected Consolidated Financial and Operating Data—Non-GAAP Financial Measures."

(4) Distributable Cash Flow is net income plus depreciation and amortization and deferred taxes, adjusted for losses/(gains) on mark-to-market derivative contracts, less maintenance capital expenditures. See “ — How We Evaluate Our Operations — Distributable Cash Flow” and “Selected Consolidated Financial and Operating Data — Non-GAAP Financial Measures.”

(5) Gathering throughput represents the volume of natural gas gathered and passed through natural gas gathering pipelines from connections to producing wells and central delivery points.

(6) Plant natural gas inlet represented the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

(7) Plant inlet volumes include producer take-in-kind, while natural gas sales exclude producer take-in-kind volumes.

(8) Gross NGL production was down during 2008 due to pipeline curtailments and, later in the year, due to unfavorable processing economics.

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

Revenues. Revenues increased by $412.6 million or 25%, to $2,074.1 million for 2008 compared to $1,661.5 million for 2007. This increase was primarily due to the following factors:

· an increase attributable to prices of $383.5 million, consisting of increases in natural gas, NGL and condensate revenues of $280.5 million, $80.8 million and $22.2 million;

· an increase attributable to volumes of $32.2 million, consisting of increases in natural gas, NGL and condensate revenues of $15.7 million, $15.5 million and $1.0 million.

· a decrease in fee and other revenues of $3.1 million.

Average realized sales prices for our sales of:

· natural gas increased by $1.85 per MMBtu, or 28%, to $8.45 per MMBtu during 2008 compared to $6.60 per MMBtu for 2007.

· NGLs increased by $0.14 per gallon, or 14%, to $1.17 per gallon for 2008 compared to $1.03 per gallon for 2007.

· condensate increased by $16.89 per Bbl, or 26%, to $82.52 per Bbl for 2008 compared to $65.62 per Bbl for 2007.

Natural gas sales volume increased by 5.4 BBtu/d or 1%, to 415.6 BBtu/d during 2008 compared to 410.2 BBtu/d for 2007 due to a lower proportion of take-in-kind volumes, increased marketing activity and the effects of unfavorable processing economics. Net NGL sales increased by 0.9 MBbl/d or 2%, to 37.3 MBbl/d for 2008 compared to 36.4 MBbl/d for 2007. Condensate sales remained flat at 3.6 MBbl/d.

Product Purchases. Product purchases during 2008 were $1,803.0 million, which increased by $396.2 million or 28%, compared to $1,406.8 million during 2007. The increase in product purchases corresponds with the increase in commodity revenue for 2008.

Operating Expenses. Operating expenses during 2008 were $55.3 million, which increased by $4.4 million or 9%, compared to $50.9 million during 2007. The increase in operating expenses was primarily the result of increases in general maintenance and supplies, lube oil, environmental and automotive expenses, compensation related expenses and ad valorem taxes.

Depreciation and Amortization Expense. Depreciation and amortization expense for 2008 was $74.3 million compared to $71.8 million for 2007, an increase of $2.5 million or 3%. The increase is due to the higher carrying value of property, plant and equipment as a result of plant and gathering system expansions.

General and Administrative Expense. General and administrative expense of $22.4 million for 2008 is an increase of $3.5 million or 19%, compared to $18.9 million for 2007. The increase included increases in professional service fees, insurance expenses, allocated corporate level expenses and other general and administrative expenses, partially offset by a decrease in compensation related expenses. For additional information regarding our allocation of general and administrative costs, see "Item 13. Certain Relationships and Related Transactions, and Director Independence-Omnibus Agreement" in this Annual Report.

Interest Expense. Interest expense for 2008 was $38.3 million compared to $41.4 million in 2007. Excluding interest expense allocated from our parent of $19.4 million in 2007 for the periods prior to our acquisition of our businesses from Targa, our interest expense increased by $16.3 million, because the debt portion of our acquisition financing was outstanding for the full year in 2008 and due to higher interest expense on our senior secured notes as compared to our credit facility.

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

Revenues. Revenues decreased by $77.0 million or 4.4%, to $1,661.5 million for 2007 compared to $1,738.5 million for 2006. This decrease was primarily due to the following:

- a net increase attributable to prices of $102.5 million, consisting of a decrease in natural gas revenues of $3.9 million and increases in NGL and condensate revenues of $99.0 million and $7.4 million;
- a net decrease attributable to volumes of $181.2 million, consisting of a decrease in natural gas revenues of $191.6 million and increases of NGL and condensate revenues of $5.7 million and $4.8 million; and
- an increase in fee and other revenues of $1.6 million.

Average realized prices for our sales of:

- natural gas decreased by $0.03 per MMBtu or less than 1%, to $6.60 per MMBtu during 2007 compared to $6.63 per MMBtu for 2006.
- NGLs increased by $0.18 per gallon or 21%, to $1.03 per gallon for 2007 compared to $0.85 per gallon for 2006.
- condensate increased by $5.75 per Bbl or 10%, to $65.62 per Bbl for 2007 compared to $59.87 per Bbl for 2006.

Natural gas sales volume decreased by 79.2 BBtu/d or 16%, to 410.2 BBtu/d during 2007 compared to 489.4 BBtu/d for 2006. The decrease in sales of natural gas volumes was attributable to a net decrease in natural gas purchased from affiliates and increased take-in-kind volumes by producers for whom we process natural gas, offset by net increases in other non-wellhead supply sources and wellhead supplies attributable to additional well connections which were partially offset by the natural decline of field production. Net NGL sales increased by 0.4 MBbl/d or 1%, to 36.4 MBbl/d for 2007 compared to 36.0 MBbl/d for 2006. The volume increase was primarily attributable to additional well connections partially offset by the natural decline in field production. Condensate production increased by 0.3 MBbl/d or 9%, to 3.6 MBbl/d for 2007 compared to 3.3 MBbl/d for 2006.

Product Purchases. Product purchases during 2007 were $1,406.8 million, a decrease of $110.9 million or 7%, compared to $1,517.7 million during 2006.

Operating Expenses. Operating expenses during 2007 were $50.9 million, an increase of $1.8 million or 4%, compared to $49.1 million during 2006. The increase was partially attributable to increased operating costs due to our processing plant and gathering system expansions, as well as increased prices for labor, supplies and equipment.

Depreciation and Amortization Expense. Depreciation and amortization expense for 2007 was $71.8 million compared to $69.9 million for 2006, an increase of $1.9 million or 3%. The increase is due to the higher carrying value of property, plant and equipment as a result of plant and gathering system expansions.

General and Administrative Expense. General and administrative expense of $18.9 million for 2007 is an increase of $2.8 million or 17%, compared to $16.1 million for 2006. The general and administrative expense increase was primarily attributable to higher direct general and administrative costs of being a public reporting entity in 2007 of approximately $3.1 million.

Interest Expense. Interest expense for 2007 was $41.4 million. Allocated interest expense from Targa in 2006 was $88.0 million. Interest expense in 2007 consisted of (i) a $9.6 million allocation from Targa for the periods from January 1, 2007 through October 24, 2007 related to the SAOU and LOU Systems, (ii) a $9.8 million allocation from January 1 through February 13, 2007 related to the North Texas System and (iii) $22.0 million of interest for borrowings under our credit facility. See "—Liquidity and Capital Resources" for additional information regarding our outstanding debt obligations.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, to meet our indebtedness obligations, to refinance our indebtedness, to meet our collateral requirements, or to pay our distributions depends on our ability to generate cash in the future. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, particularly for natural gas and NGLs, operating costs and maintenance capital expenditures. See "Item 1A.—Risk Factors."

Our main sources of liquidity and capital resources are internally generated cash flow from operations, a credit facility with both uncommitted and committed availability and access to both the debt and equity capital markets. The credit markets are undergoing significant volatility. Many financial institutions have liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our exposure to the current credit crisis includes our credit facility, cash investments and counterparty performance risks. Continued volatility in the capital markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets. In order to increase our cash position in the face of the credit and capital market disruptions, on October 16, 2008, we requested a $100 million funding under our credit facility. Lehman Bank, a lender under our credit facility, defaulted on its portion of this borrowing request resulting in actual funding of $97.8 million. As a result of the default by Lehman Bank, we believe the availability under our credit facility has been effectively reduced by approximately $10.0 million.

Current market conditions also elevate the concern over counterparty risks related to our commodity derivative contracts and trade credit. We have all of our commodity derivatives with major financial institutions. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices which could have a materially adverse effect on our results of operations. We sell a significant portion of our natural gas, NGLs and condensate to Targa and a variety of other purchasers. Non-performance by a trade creditor could result in losses.

Crude oil and natural gas prices are also volatile and have declined significantly during the later half of 2008. In a continuing effort to reduce the volatility of our cash flows, we have periodically entered into commodity contracts for a portion of our estimated equity volumes through 2012. See "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk" and Note 9 to our Consolidated Financial Statements beginning on page F-1 of this Annual Report. The current market conditions may also impact our ability to enter into future commodity derivative contracts. In the event of a global recession, commodity prices may stay depressed or fall further thereby causing a prolonged downturn, which could reduce our operating margins and cash flow from operations.

As of December 31, 2008, we had liquidity of $424.3 million, including $81.8 million of cash and $342.5 million of additional borrowing capacity available under our credit facility. We will continue to monitor our liquidity and conditions in the capital markets. Additionally, we will continue to monitor events and circumstances surrounding each of the other twenty three lenders under our credit facility. To date, other than the Lehman Bank default, we have experienced no disruptions in our ability to access funds committed under our credit facility. However, we cannot predict with any certainty the impact to us of any further disruptions in the credit environment. See "Item 1A. Risk Factors" in this Annual Report.

Historically, our cash generated from operations has been sufficient to finance our operating expenditures and fund most of our maintenance and expansion capital expenditures, with remaining amounts being distributed to Targa during its period of ownership and to our unitholders since our IPO.

We believe that cash generated from operations along with availability under our credit facility will be sufficient to meet our working capital requirements, capital expenditure requirements and our minimum quarterly cash distributions for at least the next year.

We intend to make cash distributions to our unitholders and our general partner in an amount at least equal to the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures. Historically, we have relied on internally generated cash flows for these purposes. See "—Factors That Significantly Affect Our Results—Distributions to our Unitholders" for a table that shows the distributions we declared subsequent to the fourth quarter of 2008 and distributions declared and paid in 2008 and 2007.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. Our working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that we buy and sell. In general, our working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, our working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by our customers or paid to our suppliers can also cause fluctuations in working capital because we settle with most of our larger suppliers and customers on a monthly basis and often near the end of the month. We expect that our future working capital requirements will be impacted by these same factors.

Prior to our IPO and the contribution of the North Texas System in February 2007 and the acquisition of the SAOU and LOU Systems in October 2007, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with Targa, but were recorded as an adjustment to parent equity on the balance sheet. The primary transactions between Targa and us are natural gas and NGL sales, the provision of operations and maintenance activities and the provision of general and administrative services. As a result of this accounting treatment, our working capital did not reflect any affiliate accounts receivable for intercompany commodity sales or any affiliate accounts payable for the personnel and services provided by or paid for by our parent prior to the acquisition of the North Texas System and the subsequent acquisition of the SAOU and LOU Systems.

As of December 31, 2008, we had a positive working capital balance of $149.0 million.

Cash Flow. Net cash provided by or used in operating activities, investing activities and financing activities for 2008, 2007 and 2006 were as follows:

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Net cash provided by (used in):			
Operating activities	$ 95.2	$ 270.5	$ 124.4
Investing activities	(51.0)	(40.7)	(32.9)
Financing activities	(13.5)	(178.8)	(91.5)

Operating Activities. Net cash provided by operating activities for 2008 decreased by $175.3 million or 65% compared to 2007. This decrease is primarily attributable to a decrease in working capital balances and an $87.4 million payment to terminate certain out-of-the-money commodity derivatives, partially offset by a $51.2 million increase in net income.

Net cash provided by operating activities increased by $146.1 million or 117%, for 2007 compared to 2006. This increase is attributable to an increase in our net income, increased non-cash charges and increases in working capital balances.

Investing Activities. Net cash used in investing activities for 2008 increased $10.3 million or 25% compared to 2007. The increase is primarily from increased expenditures related to gathering system expansion projects begun in the third quarter of 2008.

Net cash used in investing activities for 2007 increased $7.8 million or 24%, compared to 2006, primarily due to the completion of gathering system expansion projects and higher major maintenance expenditures. The increase of $5.6 million in expansion projects and major maintenance expenditures resulted from the increased size of our gathering systems and the effect of higher utilization of our field compression facilities.

Financing Activities. Net cash used in financing activities for 2008 decreased by $165.3 million, or 92% compared to 2007. Cash flows from financing activities during 2007 included activity related to our IPO and our acquisition from Targa of the SAOU and LOU systems. During 2008, net borrowings of $111.5 million were offset by a $26.8 million payment to repurchase approximately $40 million of our senior notes and a $59.7 million increase in distributions to our unitholders.

The net cash used in financing activities for 2007 increased by $87.3 million compared to 2006. This increase primarily reflects the proceeds from our equity offerings, borrowings under our credit facility and deemed parent contributions prior to the contribution or transfer of assets to us, partially offset by payments of debt, offering costs, debt issuance costs related to our credit facility, distributions to our equity holders and payments to Targa for assets transferred under common control.

Capital Requirements. The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. A significant portion of the cost of constructing new gathering lines to connect to our gathering system is generally paid for by the natural gas producer. However, we expect to incur significant expenditures throughout 2009 related to the expansion of our natural gas gathering and processing infrastructure.

We categorize our capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets including the replacement of system components and equipment which is worn, obsolete or completing its useful life, the addition of new sources of natural gas supply to our systems to replace natural gas production declines and expenditures to remain in compliance with environmental laws and regulations. Expansion expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues.

	Year Ended December 31,		
	2008	**2007**	**2006**
		(In millions)	
Capital expenditures:			
Expansion	$ 28.0	$ 22.4	$ 16.0
Maintenance	26.6	21.5	16.3
	$ 54.6	$ 43.9	$ 32.3

We estimate that our capital expenditures will be approximately $60 million in 2009, of which approximately $20 million will be for maintenance. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets. Expansion capital expenditures may vary significantly based on investment opportunities.

Description of Senior Notes. On June 12, 2008, we entered into a purchase agreement to issue and sell $250,000,000 in aggregate principal amount of our $8^1/4$% senior unsecured notes due 2016 (the “Notes”). On June 18, 2008, in connection with the issuance of the Notes, we entered into an Indenture (the “Indenture”) governing the terms of the Notes.

The Notes will mature on July 1, 2016 and interest is payable on the Notes semi-annually in arrears on each January 1 and July 1. The Notes are guaranteed on a senior unsecured basis by certain of our subsidiaries.

The Indenture restricts our ability to make distributions to unitholders if we are in default or an event of default (as defined in the Indenture) exists. It also restricts our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase, equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the Indenture) has occurred and is continuing, many of such covenants will terminate and we and our subsidiaries will cease to be subject to such covenants.

Description of Senior Secured Credit Agreement. See Note 10 to our Consolidated Financial Statements beginning on page F-1 of this Annual Report for a complete description of our Senior Secured Credit Facility..

Contractual Obligations. Following is a summary of our contractual cash obligations over the next several fiscal years, as of December 31, 2008:

	Payments Due By Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**More Than 5 Years**
			(In millions)		
Debt obligations (1)	$ 696.9	$ -	$ -	$ 487.8	$ 209.1
Interest on debt obligations (2)	159.8	27.0	54.0	35.7	43.1
Capacity payments (3)	8.2	5.4	2.8	-	-
Right-of-way	4.9	0.3	0.7	0.6	3.3
Asset retirement obligation	3.5	-	-	-	3.5
	$ 873.3	$ 32.7	$ 57.5	$ 524.1	$ 259.0

(1) Represents $209.1 million outstanding on the 8¼% senior notes due July 1, 2016 and $487.8 million outstanding under our $850 million senior secured credit facility. As of December 31, 2008, we had availability under our credit facility of $342.5 million, after giving effect to outstanding borrowings of $487.8 million, $9.7 million of issued letters of credit and the Lehman Bank default of approximately $10.0 million.

(2) Represents interest expense on our debt, based on interest rates as of December 31, 2008.

(3) Consists of payments for firm natural gas pipeline capacity.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas and NGLs, changes in interest rates, as well as nonperformance by our customers. We do not use risk sensitive instruments for trading purposes.

Commodity Price Risk. A majority of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the natural gas and/or NGLs or equity volumes, as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge our exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2008, we have hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the years 2009 through 2012 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages of our expected equity volumes that are hedged decrease over time. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGL and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. We intend to continue to manage our exposure to commodity prices in the future by entering into similar hedge transactions using swaps, collars, purchased puts (or floors) or other hedge instruments as market conditions permit.

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover baskets of ethane, propane, normal butane, iso-butane and natural gasoline based upon our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Additionally, our NGL hedges are based on published index prices for delivery at Mont Belvieu and our natural gas hedges are based on published index prices for delivery at Waha and Mid-Continent, which closely approximate our actual NGL and natural gas delivery points. We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

Our commodity price hedging transactions are typically documented pursuant to a standard International Swap Dealers Association (“ISDA”) form with customized credit and legal terms. Our principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges, are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. As long as this first priority lien is in effect, we expect to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time even if our counterparty’s exposure to our credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in our creditworthiness. A purchased put (or floor) transaction does not create credit exposure to us for our counterparties.

During 2008, 2007 and 2006, we entered into hedging arrangements for a portion of our forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During 2008, 2007 and 2006, our operating revenues were adjusted by net hedge losses of $33.7 million, $1.0 million and $0.9 million.

As of December 31, 2008, our commodity hedges were as follows:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per day 2009	2010	2011	2012	Fair Value
							(In thousands)
Natural Gas Sales							
Swap	IF-HSC	7.39	1,966	-	-	-	$ 1,159
			1,966	-	-	-	
Swap	IF-NGPL MC	9.18	6,256	-	-	-	9,466
Swap	IF-NGPL MC	8.86	-	5,685	-	-	5,129
Swap	IF-NGPL MC	7.34	-	-	2,750	-	843
Swap	IF-NGPL MC	7.18	-	-	-	2,750	738
			6,256	5,685	2,750	2,750	
Swap	IF-Waha	8.73	6,936	-	-	-	8,627
Swap	IF-Waha	7.52	-	5,709	-	-	2,294
Swap	IF-Waha	7.36	-	-	3,250	-	886
Swap	IF-Waha	7.18	-	-	-	3,250	708
			6,936	5,709	3,250	3,250	
Total Swaps			15,158	11,394	6,000	6,000	
Floor	IF-NGPL MC	6.55	850	-	-	-	574
			850	-	-	-	
Floor	IF-Waha	6.55	565	-	-	-	326
			565	-	-	-	
Total Floors			1,415	-	-	-	
Total Sales			16,573	11,394	6,000	6,000	
							$ 30,750

NGL

Instrument Type	Index	Avg. Price $/gal	Barrels per day 2009	2010	2011	2012	Fair Value
							(In thousands)
NGL Sales							
Swap	OPIS-MB	1.32	6,248	-	-	-	$ 66,137
Swap	OPIS-MB	1.27	-	4,809	-	-	39,122
Swap	OPIS-MB	0.92	-	-	3,400	-	8,288
Swap	OPIS-MB	0.92	-	-	-	2,700	6,018
Total Swaps			6,248	4,809	3,400	2,700	
Floor	OPIS-MB	1.44	-	-	199	-	1,807
Floor	OPIS-MB	1.43	-	-	-	231	1,932
Total Floors			-	-	199	231	
Total Sales			6,248	4,809	3,599	2,931	
							$ 123,304

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per day 2009	2010	2011	2012	Fair Value
							(In thousands)
Condensate Sales							
Swap	NY-WTI	69.00	322	-	-	-	$ 1,655
Swap	NY-WTI	68.10	-	301	-	-	431
Total Swaps			322	301	-	-	
Floor	NY-WTI	60.00	50	-	-	-	239
Total Floors			50	-	-	-	
Total Sales			372	301	-	-	
							$ 2,325

These contracts may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our variable rate debt under our credit facility. To the extent that interest rates increase, our interest expense for our revolving debt will also increase. As of December 31, 2008, there were borrowings of approximately $487.8 million outstanding under our $850 million credit facility.

As of December 31, 2008 we had the following open interest rate swaps:

Expiration Date	Fixed Rate	Notional Amount Amount	Fair Value
			(In thousands)
January 24, 2011	4.00%	$100 million	$ (5,282)
January 24, 2012	3.75%	200 million	(12,294)
			$ (17,576)

We have designated all interest rate swaps as cash flow hedges. Accordingly, unrealized gains and losses relating to the interest rate swaps are recorded in OCI until the interest expense on the related debt is recognized in earnings. A hypothetical increase of 100 basis points in the underlying interest rate, after taking into account our interest rate swaps, would increase our annual interest expense by $1.9 million.

Credit Risk. We are subject to risk of losses resulting from nonpayment or nonperformance by our customers. We operate under the Targa credit policy and closely monitor the creditworthiness of customers to whom we grant credit and establish credit limits in accordance with this credit policy. In addition to third party contracts, we have entered into several agreements with Targa. For example, we are party to natural gas, NGL and condensate purchase agreements pursuant to which Targa purchases the majority of our natural gas, NGLs and high-pressure condensate. In addition, we are also a party to an omnibus agreement with Targa which addresses, among other things, the provision of general and administrative and operating services to us. Any material nonperformance under the omnibus and purchase agreements by Targa could materially and adversely impact our ability to operate and make distributions to our unitholders.

As of December 31, 2008, affiliates of Goldman Sachs, Merrill Lynch and Barclays Bank accounted for 67%, 21% and 11% of our counterparty credit exposure related to commodity derivative instruments. Goldman Sachs, Merrill Lynch and Barclays Bank are major financial institutions, each possessing investment grade credit ratings, based upon minimum credit ratings assigned by Standard & Poor’s Ratings Services, a division of the McGraw-Hill Companies, Inc.

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

Our Consolidated Financial Statements, together with the report of our independent registered public accounting firm begin on page F-1 of this Annual Report.

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

None.

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

Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of our general partner, after evaluating the effectiveness of the Partnership's "disclosure controls and procedures" (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")), as of December 31, 2008, have concluded that as of December 31, 2008, the Partnership's disclosure controls and procedures were effective and designed to provide reasonable assurance that information required to be disclosed by the Partnership in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Commission' rules and forms and accumulated and communicated to the Partnership's management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosures.

Internal Control Over Financial Reporting

(a) **Management's Report on Internal Control Over Financial Reporting**

The management of our general partner is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). The general partner's management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the Partnership's internal control over financial reporting based on the *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, the general partner's management concluded that the Partnership's internal control over financial reporting was effective as of December 31, 2008 as stated in its report included in our consolidated financial statements on page F-2 of this Annual Report, which is incorporated herein by reference.

(b) Report of Independent Registered Public Accounting Firm

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report included in our Consolidated Financial Statements on page F-3 of this Annual Report which is incorporated herein by reference.

(c) Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2008, there were no changes in the Partnership's internal control over financial reporting that have materially affected or are reasonably likely to materially affect, the Partnership's internal control over financial reporting.

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

Not applicable.

Part III

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

We are a limited partnership and, therefore, have no officers or directors.

Management of Targa Resources Partners LP

Targa Resources GP LLC, our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders, but our partnership agreement contains various provisions modifying and restricting the fiduciary duty. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

The directors of our general partner oversee our operations. Our general partner currently has seven directors. Targa elects all members to the board of directors of our general partner and our general partner has three directors that are independent as defined under the independence standards established by The NASDAQ Stock Market LLC. The NASDAQ Stock Market LLC does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee.

Our general partner has a standing Audit Committee that consists of three directors. Messrs. Robert B. Evans, Barry R. Pearl and William D. Sullivan serve as the members of the Audit Committee. The Board of Directors of our general partner has affirmatively determined that Messrs. Evans, Pearl and Sullivan are independent as described in the rules of The NASDAQ Stock Market LLC and the Exchange Act, as amended. In addition, the Board of Directors of our general partner has determined that, based upon relevant experience, Audit Committee member Barry R. Pearl is an “audit committee financial expert” as defined in Item 407 of Regulation S-K of the Exchange Act, as amended. Mr. Pearl serves as the Chairman of the Audit Committee. The Audit Committee assists the board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The Audit Committee has sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The Audit Committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the Audit Committee.

The compensation of our general partner’s executive officers is set by Targa, with the board of directors of our general partner playing no role in the process. Compensation decisions relating to oversight of the long-term incentive plan described below, however, are made by the board of directors of our general partner. While the board may establish a compensation committee in the future, it has no current plans to do so.

Three independent members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. Messrs. Evans, Pearl and Sullivan serve as the members of the conflicts committee. Mr. Pearl serves as the Chairman of the Conflicts Committee. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates and must meet the independence and experience standards established by The NASDAQ Stock Market LLC and the Exchange Act, amended, to serve on an audit committee of a board of directors and certain other requirements. Any matters approved by the conflicts committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

All of our executive management personnel are employees of Targa and devote their time as needed to conduct our business and affairs. These officers of Targa Resources GP LLC manage the day-to-day affairs of our business. We also utilize a significant number of employees of Targa to operate our business and provide us with general and administrative services. We reimburse Targa for allocated expenses of operational personnel who perform services for our benefit, allocated general and administrative expenses and certain direct expenses. See "Reimbursement of Expenses of Our General Partner" included in this Item 10.

Directors and Executive Officers

The following table shows information regarding the current directors and executive officers of Targa Resources GP LLC.

Name	Age(1)	Position with Targa Resources GP LLC
Rene R. Joyce	61	Chief Executive Officer and Director
Joe Bob Perkins	48	President
James W. Whalen	67	President — Finance and Administration and Director
Roy E. Johnson	64	Executive Vice President
Michael A. Heim	60	Executive Vice President and Chief Operating Officer
Jeffrey J. McParland	54	Executive Vice President and Chief Financial Officer
Paul W. Chung	48	Executive Vice President, General Counsel and Secretary
Peter R. Kagan	40	Director
Chansoo Joung	48	Director
Robert B. Evans	60	Director
Barry R. Pearl	59	Director
William D. Sullivan	52	Director

(1) As of February 25, 2009

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors of our general partner. There are no family relationships among any of our directors or executive officers.

Rene R. Joyce has served as a director and Chief Executive Officer of our general partner since October 2006 and of Targa since its formation in February 2004 and was a consultant for the Targa predecessor company during 2003. He is also a member of the supervisory directors of Core Laboratories N.V. Mr. Joyce served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Joyce served as President of onshore pipeline operations of Coral Energy, LLC, a subsidiary of Shell Oil Company ("Shell") from 1998 through 1999 and President of energy services of Coral Energy Holding, L.P. ("Coral") a subsidiary of Shell which was the gas and power marketing joint venture between Shell and Tejas Gas Corporation ("Tejas") during 1999. Mr. Joyce served as President of various operating subsidiaries of Tejas, a natural gas pipeline company, from 1990 until 1998 when Tejas was acquired by Shell.

Joe Bob Perkins has served as President of our general partner since October 2006 and of Targa since February 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Perkins also served as a consultant in the energy industry from 2002 through 2003 and was an active partner in RTM Media (an outdoor advertising firm) during such time period. Mr. Perkins served as President and Chief Operating Officer for the Wholesale Businesses, Wholesale Group and Power Generation Group of Reliant Resources, Inc. and its parent/predecessor companies, from 1998 to 2002 and Vice President, Corporate Planning and Development of Houston Industries from 1996 to 1998. He served as Vice President, Business Development, of Coral from 1995 to 1996 and as Director, Business Development, of Tejas from 1994 to 1995. Prior to 1994, Mr. Perkins held various positions with the consulting firm of McKinsey & Company and with an exploration and production company.

James W. Whalen has served as a director of our general partner since February 2007 and has served as President-Finance and Administration of our general partner since October 2006 and of Targa since January 2006 and as a director of Targa since May 2004. Since November 2005, Mr. Whalen has served as President — Finance and Administration for various Targa subsidiaries. Between October 2002 and October 2005, Mr. Whalen served as the Senior Vice President and Chief Financial Officer of Parker Drilling Company. Between January 2002 and October 2002, he was the Chief Financial Officer of Diversified Diagnostic Products, Inc. He served as Chief Commercial Officer of Coral from February 1998 through January 2000. Previously, he served as Chief Financial Officer for Tejas from 1992 to 1998. Mr. Whalen is also a director of Parker Drilling Company and Equitable Resources, Inc.

Roy E. Johnson has served as Executive Vice President of our general partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Johnson also served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. He served as Vice President, Business Development and President of the International Group of Tejas from 1995 to 2000. In these positions, he was responsible for acquisitions, pipeline expansion and development projects in North and South America. Mr. Johnson served as President of Louisiana Resources Company, a company engaged in intrastate natural gas transmission, from 1992 to 1995. Prior to 1992, Mr. Johnson held various positions with a number of different companies in the upstream and downstream energy industry.

Michael A. Heim has served as Executive Vice President and Chief Operating Officer of our general partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. Mr. Heim also served as a consultant in the energy industry from 2001 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Heim served as Chief Operating Officer and Executive Vice President of Coastal Field Services, a subsidiary of The Coastal Corp. (“Coastal”), a diversified energy company, from 1997 to 2001 and President of Coastal States Gas Transmission Company from 1997 to 2001. In these positions, he was responsible for Coastal’s midstream gathering, processing and marketing businesses. Prior to 1997, he served as an officer of several other Coastal exploration and production, marketing and midstream subsidiaries.

Jeffrey J. McParland has served as Executive Vice President and Chief Financial Officer of our general partner since October 2006 and of Targa since April 2004 and was a consultant for the Targa predecessor company during 2003. He served as a director of our general partner from October 2006 to February 2007. Mr. McParland served as Treasurer of our general partner from October 2006 until May 2007 and he has served as Treasurer of Targa from April 2004 until May 2007. Mr. McParland served as Secretary of Targa since February 2004 until May 2004, at which time he was elected as Assistant Secretary. Mr. McParland served as Senior Vice President, Finance of Dynegy Inc., a company engaged in power generation, the midstream natural gas business and energy marketing, from 2000 to 2002. In this position, he was responsible for corporate finance and treasury operations activities. He served as Senior Vice President, Chief Financial Officer and Treasurer of PG&E Gas Transmission, a midstream natural gas and regulated natural gas pipeline company, from 1999 to 2000. Prior to 1999, he worked in various engineering and finance positions with companies in the power generation and engineering and construction industries.

Paul W. Chung has served as Executive Vice President, General Counsel and Secretary of our general partner since October 2006 and of Targa since May 2004. Mr. Chung served as Executive Vice President and General Counsel of Coral from 1999 to April 2004; Shell Trading North America Company, a subsidiary of Shell, from 2001 to April 2004; and Coral Energy, LLC from 1999 to 2001. In these positions, he was responsible for all legal and regulatory affairs. He served as Vice President and Assistant General Counsel of Tejas from 1996 to 1999. Prior to 1996, Mr. Chung held a number of legal positions with different companies, including the law firm of Vinson & Elkins L.L.P.

Peter R. Kagan has served as a director of our general partner since February 2007 and has served as a director of Targa since February 2004. Mr. Kagan is a Managing Director of Warburg Pincus LLC and a general partner of Warburg Pincus & Co., where he has been employed since 1997 and became a partner of Warburg Pincus & Co. in 2002. He is also a member of Warburg Pincus’ Executive Management Group. He is also a director of Antero Resources Corporation, Broad Oak Energy, Inc. (“Broad Oak”), Canbriam Energy, Fairfield Energy Limited, Laredo Petroleum, MEG Energy Corp. and Universal Space Network, Inc.

Chansoo Joung has served as a director of our general partner since February 2007 and has served as a director of Targa since December 2005. Mr. Joung is a Member and Managing Director of Warburg Pincus LLC, where he has been employed since 2005 and became a partner of Warburg Pincus & Co. in 2005. Prior to joining Warburg Pincus, Mr. Joung was head of the Americas Natural Resources Group in the investment banking division of Goldman Sachs. He joined Goldman Sachs in 1987 and served in the Corporate Finance and Mergers and Acquisitions departments and also founded and led the European Energy Group. He is a director of APT Generation, Broad Oak, Ceres, Inc. and Floridian Natural Gas Storage Company.

Robert B. Evans has served as a director of our general partner since February 2007. Mr. Evans was the President and Chief Executive Officer of Duke Energy Americas, a business unit of Duke Energy Corp., from January 2004 to March 2006, after which he retired. Mr. Evans served as the transition executive for Energy Services, a business unit of Duke Energy, during 2003. Mr. Evans also served as President of Duke Energy Gas Transmission beginning in 1998 and was named President and Chief Executive Officer in 2002. Prior to his employment at Duke Energy, Mr. Evans served as Vice President of marketing and regulatory affairs for Texas Eastern Transmission and Algonquin Gas Transmission from 1996 to 1998.

Barry R. Pearl has served as a director of our general partner since February 2007. Mr. Pearl is a principal of Kealine LLC, a private developer and operator of petroleum infrastructure facilities and is a director of Seaspan Corporation and Kayne Anderson Energy Development Company. Mr. Pearl served as President and Chief Executive Officer of TEPPCO Partners from May 2002 until December 2005 and as President and Chief Operating Officer from February 2001 through April 2002. Mr. Pearl served as Vice President of Finance and Chief Financial Officer of Maverick Tube Corporation from June 1998 until December 2000. From 1984 to 1998, Mr. Pearl was Vice President of Operations, Senior Vice President of business development and planning and Senior Vice President and Chief Financial Officer of Santa Fe Pacific Pipeline Partners, L.P.

William D. Sullivan has served as a director of our general partner since February 2007. Mr. Sullivan served as President and Chief Executive Officer of Leor Energy LP from June 15, 2005 to August 5, 2005. Between 1981 and August 2003, Mr. Sullivan was employed in various capacities by Anadarko Petroleum Corporation, including serving as Executive Vice President, Exploration and Production between August 2001 and August 2003. Since Mr. Sullivan's departure from Anadarko Petroleum Corporation in August 2003, he has served on various private energy company boards. Mr. Sullivan is a director of St. Mary Land & Exploration Company, Legacy Reserves GP, LLC and Tetra Technologies, Inc.

Reimbursement of Expenses of our General Partner

Under the terms of the Omnibus Agreement, we reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel and for the provision of various general and administrative services for our benefit. With respect to the North Texas System, we reimburse Targa for the following expenses:

- general and administrative expenses, which are capped at $5 million annually for three years (ending February 2010), subject to increases based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of our conflicts committee; thereafter, our general partner will determine the general and administrative expenses to be allocated to us in accordance with our partnership agreement; and

- operations and certain direct expenses, which are not subject to the $5 million cap for general and administrative expenses.

With respect to the SAOU and LOU Systems, we will reimburse Targa for the following expenses:

- general and administrative expenses, which are not capped, allocated to the SAOU and LOU Systems according to Targa's allocation practice; and

- operating and certain direct expenses, which are not capped.

Pursuant to these arrangements, Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We reimburse Targa for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits.

General and administrative costs will continue to be allocated to the SAOU and LOU Systems according to Targa's allocation practice.

Code of Ethics

Our general partner has adopted a Code of Ethics For Chief Executive Officer and Senior Financial Officers (the "Code of Ethics"), which applies to our general partner's Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller and all other senior financial and accounting officers of our general partner. In accordance with the disclosure requirements of applicable law or regulation, we intend to disclose any amendment to or waiver from, any provision of the Code of Ethics under Item 10 of a current report on Form 8-K.

We make available, free of charge within the "Corporate Governance" section of our website at www.targaresources.com and in print to any unitholder who so requests, the Code of Ethics and the Audit Committee Charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Partners LP, 1000 Louisiana, Suite 4300, Houston, Texas 77002 or telephone (713) 584-1000. The information contained on or connected to, our internet website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that the we file with or furnish to the SEC.

Section 16(A) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers and 10% unitholders to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Form 3, 4 and 5 reports furnished to us and certifications from our directors and executive officers, we believe that during 2008, all of our directors, executive officers and beneficial owners of more than 10% of our common units complied with Section 16(a) filing requirements applicable to them.

Item 11. *Executive Compensation*

Executive Compensation

Compensation Discussion and Analysis

The following discussion and analysis contains statements regarding our and our executive officers' future performance targets and goals. These targets and goals are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance.

Overview

We do not directly employ any of the persons responsible for managing our business. Any compensation decisions that are required to be made by our general partner will be made by its board of directors (the "Board"), which does not have a compensation committee. All of our executive officers are employees of Targa Resources LLC, a wholly-owned subsidiary of Targa and serve in the same capacities for Targa. All of the outstanding equity of Targa is held indirectly by Targa Resources Investments Inc. ("Targa Investments"). We reimburse Targa and its affiliates for the compensation of our executive officers based on Targa's methodology used for allocating general and administration expenses during a period pursuant to the terms of and subject to the limitations contained in, the Amended and Restated Omnibus Agreement. During 2006, our executive officers were not specifically compensated for time expended with respect to our business or assets.

Targa Investments has ultimate decision making authority with respect to the compensation of our executive officers identified in the Summary Compensation Table ("named executive officers"). Under the terms of the Targa Investments Amended and Restated Stockholders' Agreement, as amended (the "Stockholders' Agreement"), compensatory arrangements with Targa's named executive officers, who are also our named executive officers, are required to be submitted to a vote of Targa Investments' stockholders unless such arrangements have been approved by the Compensation Committee of Targa Investments (the "TRII Compensation Committee"). As such, the TRII Compensation Committee is responsible for overseeing the development of an executive compensation philosophy, strategy, framework and individual compensation elements for our named executive officers that is based on Targa Investments' business priorities.

The following Compensation Discussion and Analysis describes the material elements of compensation for our named executive officers as determined by the TRII Compensation Committee and is presented from the perspective of our named executive officers in their roles as officers of Targa. These elements and the TRII Compensation Committee's decisions with respect to determinations on payments, are not subject to approval by the Board or the board of directors of Targa (the "Targa Board"). Certain members of the Board and the entire Targa Board, including the Targa Board's compensation committee, are members of the board of directors of Targa Investments (the "Targa Investments Board"), including the TRII Compensation Committee. Mr. Pearl, one of our directors, was an observer at the TRII Compensation Committee's meeting in January 2009. As used in this Compensation Discussion and Analysis (other than in this overview), references to "our," "we," "us," the "Company" and similar terms refer to Targa.

Compensation Philosophy

The TRII Compensation Committee believes that total compensation of executives should be competitive with the market in which we compete for executive talent — the energy industry and midstream natural gas companies. The following compensation objectives guide the TRII Compensation Committee in its deliberations about executive compensation matters:

- Provide a competitive total compensation program that enables us to attract and retain key executives;
- Ensure an alignment between our strategic and financial performance and the total compensation received by our named executive officers;
- Provide compensation for performance relative to expectations and our peer group;
- Ensure a balance between short-term and long-term compensation while emphasizing at-risk or variable, compensation as a valuable means of supporting our strategic goals and aligning the interests of our named executive officers with those of our shareholders; and
- Ensure that our total compensation program supports our business objectives and priorities.

Consistent with this philosophy and compensation objectives, we do not pay for perquisites for any of our named executive officers, other than parking subsidies.

The Role of Peer Groups and Benchmarking

Our chief executive officer (the "CEO"), president and chief financial officer (collectively, "Senior Management") review compensation practices at peer companies, as well as broader industry compensation practices, at a general level to ensure that our total compensation is reasonably comparable and meets our compensation objectives. In addition, when evaluating compensation levels for each named executive officer, the TRII Compensation Committee reviews publicly available compensation data for executives in our peer group, compensation surveys and compensation levels for each named executive officer with respect to their roles with the Company and levels of responsibility, accountability and decision-making authority. Although Senior Management and the TRII Compensation Committee consider compensation data from other companies, they do not attempt to set compensation components to meet specific benchmarks, such as salaries "above the median" or total compensation "at the 50th percentile."

For 2008, Senior Management identified peer companies in the midstream energy industry and reviewed compensation information filed by the peer companies with the SEC. The peer group reviewed by Senior Management for 2008 consisted of the following companies: Atlas America, Copano, Crosstex, DCP Midstream, Enbridge Energy Partners, Energy Transfer Partners, Magellan Midstream, MarkWest Energy Partners, Martin Midstream, NuStar Energy, Oneok Partners, Plains All American Pipeline, Regency Energy Partners, TEPPCO Partners and Williams Energy Partners.

Senior Management reviews our compensation practices and performance against peer companies on an annual basis.

Role of Senior Management in Establishing Compensation for Named Executive Officers

Typically, Senior Management consults with a compensation consultant engaged by the TRII Compensation Committee and reviews market data to determine relevant compensation levels and compensation program elements. Based on these consultations and a review of publicly available information for the peer group, Senior Management submits a proposal to the chairman of the TRII Compensation Committee. The proposal includes a recommendation of base salary, annual bonus and any new long term compensation to be paid or awarded to executive officers and employees. The chairman of the TRII Compensation Committee reviews and discusses this proposal with Senior Management and may request Senior Management for additional information or to reconsider their recommendation. The resulting recommendation is then submitted to the TRII Compensation Committee for consideration. The final compensation decisions are reported to the Targa Investments Board.

Our Senior Management has no other role in determining compensation for our executive officers, but our executive officers are delegated the authority and responsibility to determine the compensation for all other employees.

Elements of Compensation for Named Executive Officers

Our compensation philosophy for executive officers emphasizes our executives having a significant long-term equity stake. For this reason, in connection with our formation in 2004 and with the DMS Acquisition in 2005, the named executive officers were granted restricted stock and options to purchase restricted stock of Targa Investments to attract, motivate and retain our executive team. As a result, executive compensation has been weighted toward long-term equity awards. Our executive officers have also invested a significant portion of their personal investable assets in the equity of Targa Investments and have made significant investments in the equity of the Partnership. With these equity interests as context, elements of compensation for our named executive officers are the following: (i) annual base salary; (ii) discretionary annual cash awards; (iii) performance awards under Targa Investments' long-term incentive plan, (iv) contributions under our 401(k) and profit sharing plan; and (v) participation in our health and welfare plans on the same basis as all of our other employees.

Base Salary. The base salaries for our named executive officers are set and reviewed annually by the TRII Compensation Committee. The salaries are based on historical salaries paid to our named executive officers for services rendered to us, the extent of their equity ownership in Targa Investments, market data and responsibilities of our named executive officers. Base salaries are intended to provide fixed compensation comparable to market levels for similarly situated executive officers.

Annual Cash Incentives. The discretionary annual cash awards paid to our named executive officers are designed to supplement the annual base salary of our named executive officers so that, on a combined basis, the annual cash compensation for our named executive officers yield competitive cash compensation levels and drive performance in support of our business strategies. It is Targa Investments' general policy to pay these awards prior to the end of the first quarter of the next fiscal year. The payment of individual cash bonuses to employees, including our named executive officers, are subject to the sole discretion of the TRII Compensation Committee.

Our 2008 Annual Incentive Plan (the "Bonus Plan") was adopted on January 17, 2008 to reward our employees for contributions towards our achievement of financial and operational business priorities (which includes business priorities of the Partnership) approved by the TRII Compensation Committee and to aid us in retaining and motivating employees. Under the Bonus Plan and similar plans expected to be adopted in subsequent years, funding of a discretionary cash bonus pool is expected to be recommended by our CEO and approved by the TRII Compensation Committee annually based on our achievement of certain strategic, financial and operational objectives. The Bonus Plan is administered by the TRII Compensation Committee, which considers certain recommendations by the CEO. Following the end of each year, the CEO recommends to the TRII Compensation Committee the total amount of cash to be allocated to the bonus pool based upon our overall performance relative to these objectives. Upon receipt of the CEO's recommendation, the TRII Compensation Committee, in its sole discretion, determines the total amount of cash to be allocated to the bonus pool. Additionally, the TRII Compensation Committee, in its sole discretion, determines the amount of the cash bonus award to each of our executive officers, including the CEO. The executive officers determine the amount of the cash bonus pool to be allocated to certain of our departments, groups and employees (other than our executive officers) based on performance and on the recommendation of their supervisors, managers and line officers.

For 2008, the TRII Compensation Committee approved funding of the cash bonus pool with the following six key business priorities: (i) identify opportunities to strengthen organization and develop plans to address them; (ii) expand on existing processes to enhance the involvement of the organization in making our businesses better; (iii) aggressively develop attractive return projects and opportunities and proactively invest in and expand the Company's businesses; (iv) improve insurance recovery situation with resolution or clear path to resolution; (v) make a significant third-party acquisition(s) at the Partnership and/or continue to effectively drop down Company assets to the Partnership; and (vi) execute on all fronts (including the 2008 business plan and above priorities). The Bonus Plan established business priorities that the TRII Compensation Committee considers when making awards under the Bonus Plan and also established the following overall threshold, target and maximum levels for the Company's bonus pool: 50% of the cash bonus pool for the threshold level; 100% for the target level and 200% for the maximum level. The funding of the cash bonus pool and the payment of individual cash bonuses to employees, including our named executive officers, are subject to the sole discretion of the TRII Compensation Committee.

LTIP Awards. In January 2008, Targa Investments granted to the named executive officers cash-settled performance unit awards linked to the performance of the Partnership's common units that will vest in June of 2011, with the amounts vesting under such awards dependent on the Partnership's performance compared to a peer-group consisting of the Partnership and 12 other publicly traded partnerships. These performance unit awards are made pursuant to a plan adopted by Targa Investments. These awards are designed to further align the interests of the named executive officers with those of the Partnership's equity holders.

Retirement Benefits. We offer eligible employees a Section 401(k) tax-qualified, defined contribution plan to enable employees to save for retirement through a tax-advantaged combination of employee and Company contributions and to provide employees the opportunity to directly manage their retirement plan assets through a variety of investment options. Our employees, including our named executive officers, are eligible to participate in our 401(k) plan and may elect to defer up to 30% of their annual compensation on a pre-tax basis and have it contributed to the plan, subject to certain limitations under the Internal Revenue Code. In addition, we make the following contributions to the 401(k) Plan for the benefit of our employees, including our named executive officers: (i) 3% of the employee's eligible compensation; (ii) an amount equal to the employee's contributions to the 401(k) Plan up to 5% of the employee's eligible compensation and (iii) a discretionary amount depending on Targa's performance.

Health and Welfare Benefits. All full-time employees, including our named executive officers, may participate in our health and welfare benefit programs, including medical, health, life insurance and dental coverage and disability insurance.

Perquisites. We believe that the elements of executive compensation should be tied directly or indirectly to the actual performance of the Company. It is the TRII Compensation Committee's policy not to pay for perquisites for any of our named executive officers, other than parking subsidies.

Relation of Compensation Elements to Compensation Philosophy

Our named executive officers, other senior managers and directors, through a combination of personal investment and equity grants, own approximately 20% of the fully diluted equity of Targa Investments. Based on our named executive officers' ownership interests in Targa Investments and their direct ownership of the Partnership's common units, they own, directly and indirectly, approximately 3% of the Partnership's limited partner interests. The TRII Compensation Committee believes that the elements of its compensation program fit the established overall compensation objectives in the context of management's substantial ownership of our parent's equity, which allows Targa to provide competitive compensation opportunities to align and drive the performance of the named executive officers in support of Targa Investments' and our own business strategies and to attract, motivate and retain high quality talent with the skills and competencies required by Targa Investments and us.

Application of Compensation Elements

Equity Ownership. The TRII Compensation Committee did not award additional equity to the named executive officers in 2008.

Base Salary. In 2008, base salaries for our named executive officers were established based on historical levels for these officers, taking into consideration officer salaries in our peer group and the long-term equity component of our compensation program.

Annual Cash Incentives. In January 2009, the TRII Compensation Committee approved a cash bonus pool of 150% of the target level for the employee group, including our named executive officers, under the Bonus Plan for performance during 2008. The TRII Compensation Committee paid above target level bonuses under the Bonus Plan in recognition of significant efforts and organizational performance in 2008. The executive officers received bonus awards equivalent to the same percentage of target as the Company bonus pool based on our achievement of overall goals in 2008 as follows:

Rene R. Joyce	$247,500
Jeffrey J. McParland	194,250
Joe Bob Perkins	222,750
James W. Whalen	222,750
Michael A. Heim	206,250

Long-term Cash Incentives. In January 2008, Targa Investments granted executive officers of the General Partner cash-settled performance unit awards linked to the performance of the Partnership's common units that will vest in June of 2011, with the amounts vesting under such awards dependent on the Partnership's performance compared to a peer-group consisting of the Partnership and 12 other publicly traded partnerships. The peer group companies for 2008 were: Energy Transfer Partners, Oneok Partners, Copano, DCP Midstream, Regency Energy Partners, Plains All American Pipeline, MarkWest Energy Partners, Williams Energy Partners, Magellan Midstream, Martin Midstream, Enbridge Energy Partners, Crosstex and Targa Resources Partners LP. These performance unit awards were made pursuant to a plan adopted by Targa Investments and administered by Targa Resources LLC. The TRII Compensation Committee has the ability to modify the peer-group in the event a peer company is no longer determined to be one of the Partnership's peers. The cash settlement value of each performance unit award will be the value of an equivalent Partnership common unit at the time of vesting plus associated distributions over the vesting period, which may be higher or lower than the Partnership's common unit price at the time of the award. If the Partnership's performance equals or exceeds the performance for the median of the group, 100% of the award will vest. If the Partnership ranks tenth in the group, 50% of the award will vest, between tenth and seventh, 50% to 100% will vest and for a performance ranking lower than tenth, no amounts will vest. In January 2008, our named executive officers, who are also executive officers of the General Partner, received an award of performance units as follows: 4,000 performance units to Mr. Joyce, 2,700 performance units to Mr. McParland, 3,500 performance units to Mr. Perkins, 3,500 performance units to Mr. Whalen and 3,500 performance units to Mr. Heim.

Health and Welfare Benefits. For 2008, our named executive officers participated in our health and welfare benefit programs, including medical, health, life insurance, dental coverage and disability insurance.

Perquisites. Consistent with our compensation philosophy, we did not pay for perquisites for any of our named executive officers during 2008, other than parking subsidies.

Changes for 2009

Annual Cash Incentives. In light of recent economic and financial events, Senior Management developed and proposed a set of strategic priorities to the TRII Compensation Committee. In January 2009, the TRII Compensation Committee approved the Targa Investments 2009 Annual Incentive Compensation Plan (the "2009 Bonus Plan"), the cash bonus plan for performance during 2009, and, established the following eight key business priorities**:** (i) manage controllable costs to levels at or below plan levels – with a continuous effort to improve costs for 2009 and beyond; (ii) examine, prioritize and approve each capital project closely for economics (or necessity) in the current environment; (iii) increase scrutiny and proactively manage credit and liquidity across finance, credit and commercial areas; (iv) reduce (eliminate where appropriate) downstream's inventory exposure (for TRI only); (v) continue to invest in our businesses primarily within existing cash flow; (vi) pursue selected opportunities including new shale play gathering and processing build outs, other fee-based capital projects and the potential to purchase distressed strategic assets; (vii) analyze and recommend approaches to achieve maximum value; and (viii) execute on the above priorities, including the 2009 financial business plan. As with the Bonus Plan, funding of the cash bonus pool and the payment of individual cash bonuses to employees, including our named executive officers, are subject to the sole discretion of the TRII Compensation Committee.

Long-term Cash Incentives. In January 2009, our named executive officers, who are also executive officers of the General Partner, received an award of performance units under Targa Investments' long-term incentive plan as follows: 34,000 performance units to Mr. Joyce, 15,500 performance units to Mr. McParland, 20,800 performance units to Mr. Perkins and 20,800 performance units to Mr. Heim.

Compensation Committee Interlocks and Insider Participation

Our general partner does not maintain a compensation committee. The following officers of our general partner participated in deliberations of the Compensation Committee of Targa Investments concerning executive officer compensation: Messrs. Joyce, Perkins, Heim, Johnson, McParland and Chung. See "Item 13. Certain Relationships and Related Transactions, and Director Independence" for a description of certain relationships and related-party transactions.

Compensation Committee Report

In fulfilling its oversight responsibilities, the Board reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on these reviews and discussions, the Board recommended that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2008 for filing with the SEC.

The information contained in this report shall not be deemed to be "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filings with the SEC or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that the Partnership specifically incorporates it by reference into a document filed under the Securities Act of 1933, as amended or the Exchange Act.

Rene R. Joyce
James W. Whalen
Peter R. Kagan
Chansoo Joung
Robert B. Evans
Barry R. Pearl
William D. Sullivan

Executive Compensation

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2008, 2007 and 2006. Additional details regarding the applicable elements of compensation in the Summary Compensation Table are provided in the footnotes following the table.

Summary Compensation Table for 2008

Name	Year	Salary	Stock Awards ($)(1)	Option Awards ($)(2)	Non-Equity Incentive Plan Compensation	All Other Compensation(3)	Total Compensation
Rene R. Joyce	2008	$ 322,500	$ 148,218	$ 1,524	$ 247,500	$ 19,205	$ 738,947
Chief Executive Officer	2007	293,750	459,769	3,244	300,000	817,963	1,874,726
	2006	266,530	312,513	3,244	264,000	25,236	871,523
Jeffrey J. McParland	2008	253,000	114,247	1,524	194,250	19,031	582,052
Executive Vice President and	2007	230,000	316,770	3,244	235,000	674,292	1,459,306
Chief Financial Officer	2006	210,280	236,720	3,244	206,400	23,086	679,730
Joe Bob Perkins	2008	290,250	126,228	1,524	222,750	19,124	659,876
President	2007	265,000	366,318	3,244	270,000	817,888	1,722,450
	2006	244,030	260,294	3,244	240,000	23,174	770,742
James W. Whalen	2008	290,250	66,488	-	222,750	18,871	598,359
President—Finance and	2007	265,000	224,796	-	270,000	817,888	1,577,684
Administration	2006	244,030	227,546	-	240,000	21,926	733,502
Michael A. Heim	2008	268,750	127,172	1,524	206,250	19,071	622,767
Executive Vice President and	2007	243,750	366,318	3,244	250,000	817,838	1,681,150
Chief Operating Officer	2006	217,791	260,294	3,244	216,000	23,111	720,440

(1) Amounts represent expense recognized for financial statement reporting purposes in accordance with SFAS 123(R) with respect to restricted stock awards and performance unit awards, disregarding any estimate of forfeitures related to service-based vesting conditions. No stock awards or performance unit awards granted to the named executive officers were forfeited during 2008. No stock awards were granted to the named executive officers during 2008. Detailed information about the amount recognized for specific awards is reported in the table under "Outstanding Equity Awards at 2008 Fiscal Year-End" below. The fair value of non-vested stock is measured on the grant date using the estimated market price of Targa Investments common stock on such date. The fair value of a performance unit is the sum of: (i) the closing price of a common unit of the Partnership on the reporting date; (ii) the fair value of an at-the-money call option on a performance unit with a grant date equal to the reporting date and an expiration date equal to the last day of the performance period; and (iii) estimated DERs. The fair value of the call options were estimated with a Black-Scholes option pricing model using a dividend yield of zero, risk-free rates of 0.9% and 0.6% for 2008 and 2007 and volatilities of 41% and 59% for the same periods.

(2) Amounts represent expense recognized for financial statement reporting purposes in accordance with SFAS 123(R) with respect to option awards, disregarding any estimate of forfeitures related to service-based vesting conditions. No option awards granted to the named executive officers were forfeited during 2008. No option awards were granted to the named executive officers during 2008. Detailed information about the amount recognized for specific awards is reported in the table under "Outstanding Equity Awards at 2008 Fiscal Year-End" below. The fair value of each option granted was estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions for 2008, 2007 and 2006, including (i) expected term of the options of ten years, (ii) a risk-free interest rate of 3.6%, 4.6% and 4.5%, (iii) expected dividend yield of 0%, and (iv) expected stock price volatility on Targa Investments' common stock of 25.5%, 29.7% and 23.8%. Our selection of the risk-free interest rate was based on published yields for United States government securities with comparable terms. Because Targa Investments is a non-public company, its expected stock price volatility was estimated based upon the historical price volatility of the Dow Jones MidCap Pipelines Index over a period equal to the expected average term of the options granted. The calculated fair value of options granted during the years ended December 31, 2008, 2007, and 2006 was $1.48, $0.63 and $0.21 per share.

(3) For 2008 "All Other Compensation" includes the (i) aggregate value of matching and non-matching contributions to our 401(k) plan and (ii) the dollar value of life insurance coverage.

Name	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance	Total
Rene R. Joyce	$ 18,400	$ 805	$ 19,205
Jeffrey J. McParland	18,400	631	19,031
Joe Bob Perkins	18,400	724	19,124
James W. Whalen	18,400	471	18,871
Michael A. Heim	18,400	671	19,071

Grants of Plan-Based Awards

The following table and the footnotes thereto provide information regarding grants of plan-based equity and non-equity awards made to the named executive officers during 2008:

	Grants of Plan Based Awards for 2008							
		Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards(2)			Grant Date Fair Value of Stock and Option Awards(3)
Name	Grant Date	Threshold	Target	2X Target	Threshold	Target (Units)	Maximum	
Mr. Joyce	N/A	$ 82,500	$ 165,000	$ 330,000				
	01/17/08					4,000		$ 148,400
Mr. McParland	N/A	58,750	117,500	259,000				
	01/17/08					2,700		100,170
Mr. Perkins	N/A	74,250	148,500	297,000				
	01/17/08					3,500		129,850
Mr. Whalen	N/A	74,250	148,500	297,000				
	01/17/08					3,500		129,850
Mr. Heim	N/A	68,750	137,500	275,000				
	01/17/08					3,500		129,850

(1) These awards were granted under the Bonus Plan. At the time the Bonus Plan was adopted, the estimated future payouts in the above table under the heading “Estimated Possible Payouts Under Non-Equity Incentive Plan Awards” represented the cash bonus pool available for awards to the named executive officers under the Bonus Plan.

(2) These performance unit awards were granted under the Targa Investments Long-Term Incentive Plan and are discussed in more detail under the heading “Compensation Discussion & Analysis — Application of Compensation Elements — Long-Term Cash Incentives.”

(3) The dollar amounts shown are determined by multiplying the number of units reported in the table by $37.10 (the per unit fair value under SFAS 123(R) on the grant date) and assume full payout under the awards at the time of vesting.

Narrative Disclosure to Summary Compensation Table and Grants of Plan Based Awards table

A discussion of 2008 salaries, bonuses and incentive plans is included in “— Compensation Discussion and Analysis.”

Targa Investments 2005 Stock Incentive Plan

Stock Option Grants. Under the Targa Investments 2005 Stock Incentive Plan, as amended (the "2005 Incentive Plan"), incentive stock options and non-incentive stock options to purchase, in the aggregate, up to 5,159,786 shares of Targa Investments' restricted stock may be granted to our employees, directors and consultants. Subject to the terms of the applicable stock option agreement, options granted under the 2005 Incentive Plan have a vesting period of four years, remain exercisable for ten years from the date of grant and have an exercise price at least equal to the fair market value of a share of restricted stock on the date of grant. Additional details relating to previously granted non-incentive stock options under the 2005 Incentive Plan are included in "— Outstanding Equity Awards at 2008 Fiscal Year-End" below.

Restricted Stock Grants. Under the 2005 Incentive Plan, up to 7,293,882 shares of restricted stock of Targa Investments may be granted to our employees, directors and consultants. Subject to the terms of the restricted stock agreement, restricted stock granted under the Incentive Plan has a vesting period of four years from the date of grant. Additional details relating to previously granted shares of common stock are included in "— Outstanding Equity Awards at 2008 Fiscal Year-End" below.

Outstanding Equity Awards at 2008 Fiscal Year-End

Targa Investments indirectly owns all of our equity interests. The following table and the footnotes related thereto provide information regarding each stock option and other equity-based awards of Targa Investments outstanding as of December 31, 2008 for each of our named executive officers.

Outstanding Equity Awards at 2008 Fiscal Year-End

	Option Awards				Stock Awards			
Name	**# Exercisable**	**# Unexercisable**	**Option Exercise Price**	**Option Expiration Date**	**Number of Shares of Stock That Have Not Vested**	**Market Value of Shares of Stock That Have Not Vested(7)**	**Equity Incentive Plan Awards: Number of Unearned Performance Units That Have Not Vested(8)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Performance Units That Have Not Vested(9)**
Rene R. Joyce	17,417	4,355 (1)	$ 0.75	10/31/15	146,840 (4)	$ 132,156	19,000	$ 194,962
	233,101	58,275 (1)	3.00	10/31/15	1,423 (5)	1,281		
	197,239	49,310 (1)	15.00	10/31/15				
	2,405	601 (2)	3.00	12/20/15				
	2,047	512 (2)	15.00	12/20/15				
Jeffrey J. McParland	17,417	4,355 (1)	0.75	10/31/15	111,024 (4)	99,922	10,900	111,505
	174,825	43,707 (1)	3.00	10/31/15	1,067 (5)	960		
	147,929	36,983 (1)	15.00	10/31/15				
	1,803	451 (2)	3.00	12/20/15				
	1,535	384 (2)	15.00	12/20/15				
Joe Bob Perkins	17,417	4,355 (1)	0.75	10/31/15	122,336 (4)	110,102	14,300	146,322
	188,811	47,203 (1)	3.00	10/31/15	1,153 (5)	1,038		
	159,765	39,940 (1)	15.00	10/31/15				
	1,949	486 (2)	3.00	12/20/15				
	1,658	415 (2)	15.00	12/20/15				
James W. Whalen	45,454	45,454 (3)	3.00	11/01/15	101,139 (6)	91,026	14,300	146,322
	153,847	38,461 (3)	15.00	11/01/15	1,110 (5)	999		
	469	468 (2)	3.00	12/20/15				
	1,597	399 (2)	15.00	12/20/15				
Michael A. Heim	17,417	4,355 (1)	0.75	10/31/15	122,336 (4)	110,102	13,500	137,971
	188,811	47,203 (1)	3.00	10/31/15	1,153 (5)	1,038		
	159,765	39,940 (1)	15.00	10/31/15				
	1,949	486 (2)	3.00	12/20/15				
	1,658	415 (2)	15.00	12/20/15				

(1) Represents options to purchase shares of Targa Investments common stock awarded on October 31, 2005. These options vest on October 31, 2009.

(2) Represents options to purchase shares of Targa Investments common stock awarded on December 20, 2005. These options vest on December 20, 2009.

(3) Represents options to purchase shares of Targa Investments common stock awarded on November 1, 2005. These options vest on November 1, 2009.
(4) Represents shares of restricted common stock of Targa Investments awarded on October 31, 2005. These shares vest on October 31, 2009.
(5) Represents shares of restricted common stock of Targa Investments awarded on December 20, 2005. These shares vest on December 20, 2009.
(6) Represents shares of restricted common stock of Targa Investments awarded on October 31, 2005 (544 shares) and November 1, 2005 (100,595 shares). These shares vest on October 31, 2009 (with respect to the October 31, 2005 awards) and November 1, 2009 (with respect to the November 1, 2005 awards).
(7) The dollar amounts shown are determined by multiplying the number of shares or units reported in the table by $0.90 (the value determined by an independent consultant pursuant to a valuation of Targa Investments' common stock as of December 31, 2008), which management believes is a reasonable approximation of the value of such stock as of December 31, 2008.
(8) Represents the number of performance units awarded on February 8, 2007 and January 17, 2008 under the Targa Investments Long-Term Incentive Plan. These awards vest in August 2010 and June 2011, respectively, based on the Partnership's performance over the applicable period measured against a peer group of companies. These awards are discussed in more detail under the heading "Compensation Discussion & Analysis — Application of Compensation Elements — Long-Term Cash Incentives."
(9) The dollar amounts shown are determined by multiplying the number of performance units reported in the table by the sum of the closing price of a common unit of the Partnership on December 31, 2008 ($7.75) and the related distribution equivalent rights for each award and assume full payout under the awards at the time of vesting.

Option Exercises and Stock Vested in 2008

The following table provides the amount realized during 2008 by each named executive officer upon the exercise of options and upon the vesting of restricted common stock.

	Option Exercises and Stock Vested for 2008			
	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise(1)	Value Realized on Exercise	Number of Shares Acquired on Vesting	Value Realized on Vesting(6)
Rene R. Joyce			677,162 (2)	$ 2,537,948
Jeffrey J. McParland			517,456 (3)	1,937,667
Joe Bob Perkins			578,065 (4)	2,162,061
James W. Whalen	137,772	$ 475,313	127,389 (5)	700,227
Michael A. Heim			578,065 (4)	2,162,061

(1) At the time of exercise of the stock options, the common stock acquired upon exercise had a value of $3.45 per share. This value was determined by an independent consultant pursuant to a valuation of Targa Investments common stock as of October 24, 2007.
(2) The shares vested as follows: 67,288 shares on January 2, 2008, 16,822 shares on April 16, 2008, 513,939 shares on April 30, 2008, 4,981 shares on June 20, 2008, 73,420 shares on October 31, 2008 and 712 shares on December 20, 2008.
(3) The shares vested as follows: 55,272 shares on January 2, 2008, 13,818 shares on April 16, 2008, 388,584 shares on April 30, 2008, 3,736 shares on June 20, 2008, 55,512 shares on October 31, 2008 and 534 shares on December 20, 2008
(4) The shares vested as follows: 67,288 shares on January 2, 2008, 16,822 shares on April 16, 2008, 428,176 shares on April 30, 2008, 4,035 shares on June 20, 2008, 61,168 shares on October 31, 2008 and 576 shares on December 20, 2008.

(5) The shares vested as follows: 20,112 shares on January 2, 2008, 5,028 shares on April 16, 2008, 544 shares on October 31, 2008, 100,595 shares on November 1, 2008 and 1,110 shares on December 20, 2008.

(6) The value realized on vesting used a per share price based on the estimated market price of Targa Investments common stock on such date. These values were determined by an independent consultant pursuant to valuations of Targa Investments common stock prepared at various times during 2008 and 2007, which management believes are reasonable approximations of the value of such stock as of the applicable dates.

Change in Control and Termination Benefits

2005 Incentive Plan. If a Change of Control or a Liquidation Event (each as defined below) or in the case of restricted stock, certain drag-along transactions, occurs during a named executive officer's employment with us, the options granted to him under Targa Investments' form of Non-Statutory Stock Option Agreement (the "Option Agreement") and/or the restricted stock granted to him under Targa Investments' form of Restricted Stock Agreement (the "Stock Agreement") will fully vest and be exercisable (in the case of options) by him so long as he remains an employee of Targa Investments.

Options granted to a named executive officer under the Option Agreement will terminate and cease to be exercisable upon the termination of his employment with Targa Investments, except that: (i) if his employment is terminated by reason of a disability, he (or his estate or the person who acquires the options by will or the laws of descent and distribution or otherwise by reason of his death) may exercise the options in full for 180 days following such termination; (ii) if he dies while employed by Targa Investments, his estate or the person who acquires the options by will or the laws of descent and distribution or otherwise by reason of his death, may exercise the options in full for 180 days following his death; or (iii) if he resigns or is terminated by Targa Investments without Cause (as defined below), then he (or his estate or the person who acquires the options by will or the laws of descent and distribution or otherwise by reason of his death) may exercise the options for three months following such resignation or termination, but only as to the options he was entitled to exercise as of the date his employment terminates.

Restricted stock granted to a named executive officer under the Stock Agreement will fully vest if his employment is terminated by reason of a disability or his death. If a named executive officer resigns or he is terminated by Targa Investments without Cause, then his unvested restricted stock is forfeited to Targa Investments for no consideration. If a named executive officer is terminated by Targa Investments for Cause, then all restricted stock (both vested and unvested) granted to him under the Stock Agreement is forfeited to Targa Investments for no consideration. For one year following a named executive officer's termination of employment, Targa Investments has the right to repurchase all of his restricted stock and other Capital Stock (as defined below), after any applicable forfeitures, at a purchase price equal to, in the case of a termination by death, disability, resignation or without Cause, the then Fair Market Value (as defined below)of such restricted stock and Capital Stock determined in accordance with the Stockholders Agreement, and, in the case of a termination with Cause, the lower of the Original Cost (as defined below) or the then Fair Market Value of such Capital Stock.

The following terms have the specified meanings for purposes of the 2005 Incentive Plan:

- *Change of Control* means, in one transaction or a series of related transactions, a consolidation, merger or any other form of corporate reorganization involving Targa Investments or a sale of Preferred Stock (or a sale of Targa Investments' common stock following conversion of the Preferred Stock) by stockholders of Targa Investments with the result immediately after such merger, consolidation, corporate reorganization or sale that (A) a single person, together with its affiliates, owns, if prior to any firm commitment underwritten offering by Targa Investments of its common stock to the public pursuant to an effective registration statement under the Securities Act (x) for which the aggregate cash proceeds to be received by Targa Investments from such offering (without deducting underwriting discounts, expenses and commissions) are at least $35,000,000 and (y) pursuant to which Targa Investments' common stock is listed for trading on the New York Stock Exchange or is admitted to trading and quoted on the NASDAQ National Market System (a "Qualified Public Offering"), either a greater number of shares of Targa Investments' common stock (calculated assuming that all shares of Preferred Stock have been converted at the specified conversion ratio) than Warburg Pincus and its affiliates then own or, in the context of a consolidation, merger or other corporate reorganization in which Targa Investments is not the surviving entity, more voting stock generally entitled to elect directors of such surviving entity (or in the case of a triangular merger, of the parent entity of such surviving entity) than Warburg Pincus and its affiliates then own or, if on or after a Qualified Public Offering, either a majority of Targa Investments' common stock calculated on a fully-diluted basis (i.e. on the basis that all shares of Preferred Stock have been converted at the specified conversion ratio, that all Management Stock is outstanding, whether vested or not and that all outstanding options to acquire Targa Investments' common stock had been exercised (whether then exercisable or not)) or, in the context of a consolidation, merger or other corporate reorganization in which Targa Investments is not the surviving entity, a majority of the voting stock generally entitled to elect directors of such surviving entity (or in the case of a triangular merger, of the parent entity of such surviving entity) calculated on a fully diluted basis and (B) Warburg Pincus and its affiliates collectively own less than a majority of the initial shares of Capital Stock outstanding on October 31, 2005 owned by them (the "Initial Shares") or, in the event such Initial Shares are converted or exchanged into other voting securities of Targa Investment or such surviving or parent entity, less than a majority of such voting securities Warburg Pincus and its affiliates would have owned had they retained all such Initial Shares;

- *Management Stock* means the shares of Targa Investments' common stock granted pursuant to the terms of the 2005 Incentive Plan, any such shares transferred to a permitted transferee and any and all securities of any kind whatsoever of Targa Investments which may be issued in respect of, in exchange for or upon conversion of such shares of common stock pursuant to a merger, consolidation, stock split, stock dividend, recapitalization of Targa Investments or otherwise;

- *Liquidation Event* means the voluntary or involuntary liquidation, dissolution or winding up of the affairs of Targa Investments; provided that neither the merger or consolidation of Targa Investments with or into another entity, nor the merger or consolidation of another entity with or into Targa Investments, nor the sale of all or substantially all of the assets of Targa Investments shall be deemed to be a Liquidation Event;

- *Cause* means discharge by Targa Investments based on (A) an employee's gross negligence or willful misconduct in the performance of duties, (B) conviction of a felony or other crime involving moral turpitude; (C) an employee's willful refusal, after fifteen days' written notice from the Targa Investments Board, to perform the material lawful duties or responsibilities required of him; (D) willful and material breach of any corporate policy or code of conduct established by Targa Investments; and (E) willfully engaging in conduct that is known or should be known to be materially injurious to Targa Investments or any of its subsidiaries;

- *Capital Stock* means any and all shares of capital stock of or other equity interests in, Targa Investments and any and all warrants, options or other rights to purchase or acquire any of the foregoing;

- *Original Cost* means, with respect to a particular share of Capital Stock, the cash amount originally paid to Targa Investments to purchase such share (or if such share was issued in respect of other shares of Targa Investments issued in connection with the merger of one of Targa Investments' subsidiaries with and into us, then the cash amount originally paid to us to purchase such other shares), subject to adjustment for subdivisions, combinations or stock dividends involving such Capital Stock or, if no cash amount was originally paid to Targa Investments to purchase such share, then no consideration (or if such share was issued in respect of other shares of Targa Investments issued in connection with the merger of one of Targa Investments' subsidiaries with and into us and such other shares were issued by us for no cash consideration, then no consideration); and

- *Fair Market Value* means the value determined by the unanimous resolution of all directors of the Targa Investments Board, provided that if the Targa Investments Board does not or is unable to make such a determination, Fair Market Value means the value determined by an investment banking firm of recognized national standing selected by a majority of the directors of the Targa Investments Board.

The following table reflects payments that would have been made to each of the named executive officers under the 2005 Incentive Plan and related agreements in the event there was a Change of Control or their employment was terminated, each as of December 31, 2008.

Name	Change of Control	Termination for Death or Disability
Rene R. Joyce	$ 134,090 (1)	$ 134,090 (1)
Jeffrey J. McParland	101,535 (2)	101,535 (2)
Joe Bob Perkins	111,793 (3)	111,793 (3)
James W. Whalen	92,025 (4)	92,025 (4)
Michael A. Heim	111,793 (5)	111,793 (5)

(1) Of this amount, $132,156 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $1,281 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; and $653 relates to the unvested options to purchase Targa Investments common stock granted on October 31, 2005.

(2) Of this amount, $99,922 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $960 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; and $653 relates to the unvested options to purchase Targa Investments common stock granted on October 31, 2005.

(3) Of this amount, $110,102 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $1,038 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; $653 relates to the unvested options to purchase Targa Investments common stock granted on October 31, 2005.

(4) Of this amount, $490 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $90,536 relates to the unvested shares of restricted stock of Targa Investments granted on November 1, 2005; and $999 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005.

(5) Of this amount, $110,102 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $1,038 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; and $653 relates to the unvested options to purchase Targa Investments common stock granted on October 31, 2005.

Long Term Incentive Plan. If a Change of Control (as defined below) occurs during the performance period established for the performance units and related distribution equivalent rights granted to a named executive officer under Targa Investments' form of Performance Unit Grant Agreement (a "Performance Unit Agreement"), the performance units and related distribution equivalent rights then credited to a named executive officer will be cancelled and the named executive officer will be paid an amount of cash equal to the sum of (i) the product of (a) the Fair Market Value (as defined below) of a common unit of the Partnership multiplied by (b) the number of performance units granted to the named executive officer, plus (ii) the amount of distribution equivalent rights then credited to the named executive officer, if any.

Performance units and the related distribution equivalent rights granted to a named executive officer under a Performance Unit Agreement will be automatically forfeited without payment upon the termination of his employment with Targa Investments and its affiliates, except that: (i) if his employment is terminated by reason of his death, a disability that entitles him to disability benefits under Targa Investments' long-term disability plan or by Targa Investments' other than for Cause (as defined below), he will be vested in his performance units that he is otherwise qualified to receive payment for based on achievement of the performance goal at the end of the Performance Period.

The following terms have the specified meanings for purposes of the Long-Term Incentive Plan:

- *Change of Control* means (i) any "person" or "group" within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than an affiliate of Targa Investments, becoming the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in the Partnership or its general partner, (ii) the limited partners of the Partnership approving, in one or a series of transactions, a plan of complete liquidation of the Partnership, (iii) the sale or other disposition by either the Partnership or its general partner of all or substantially all of its assets in one or more transactions to any person other than the Partnership's general partner or one of such general partner's affiliates or (iv) a transaction resulting in a person other than the Partnership's general partner or one of such general partner's affiliates being the general partner of the Partnership. With respect to an award subject to Section 409A of the Code, Change of Control will mean a "change of control event" as defined in the regulations and guidance issued under Section 409A of the Code.

- *Fair Market Value* means the closing sales price of a common unit of the Partnership on the principal national securities exchange or other market in which trading in such common units occurs on the applicable date (or if there is not trading in the common units on such date, on the next preceding date on which there was trading) as reported in The Wall Street Journal (or other reporting service approved by the TRII Compensation Committee). In the event the common units are not traded on a national securities exchange or other market at the time a determination of fair market value is required to be made, the determination of fair market value shall be made in good faith by the TRII Compensation Committee.

- *Cause* means (i) failure to perform assigned duties and responsibilities, (ii) engaging in conduct which is injurious (monetarily of otherwise) to Targa Investments or its affiliates, (iii) breach of any corporate policy or code of conduct established by Targa Investments or its affiliates or breach of any agreement between the named executive officer and Targa Investments or its affiliates or (iv) conviction of a misdemeanor involving moral turpitude or a felony. If the named executive officer is a party to an agreement with Targa Investments or its affiliates in which this term is defined, then that definition will apply for purposes of the Long-Term Incentive Plan and the Performance Unit Agreement.

The following table reflects payments that would have been made to each of the named executive officers under the Long-Term Incentive Plan and related agreements in the event there was a Change of Control or their employment was terminated, each as of December 31, 2008.

Name	Change of Control	Termination for Death or Disability
Rene R. Joyce	$ 194,962 (1)	$ 194,962 (1)
Jeffrey J. McParland	111,505 (2)	111,505 (2)
Joe Bob Perkins	146,322 (3)	146,322 (3)
James W. Whalen	146,322 (3)	146,322 (3)
Michael A. Heim	137,971 (4)	137,971 (4)

(1) Of this amount, $116,250 and $40,332 relate to the performance units and related distribution equivalent rights granted on February 7, 2007, respectively; and $31,000 and $7,380 relate to the performance units and related distribution equivalent rights granted on January 17, 2008, respectively.

(2) Of this amount, $63,550 and $22,048 relate to the performance units and related distribution equivalent rights granted on February 7, 2007, respectively; and $20,925 and $4,982 relate to the performance units and related distribution equivalent rights granted on January 17, 2008, respectively.

(3) Of this amount, $83,700 and $29,039 relate to the performance units and related distribution equivalent rights granted on February 7, 2007, respectively; and $27,125 and $6,458 relate to the performance units and related distribution equivalent rights granted on January 17, 2008, respectively.

(4) Of this amount, $77,500 and $26,888 relate to the performance units and related distribution equivalent rights granted on February 7, 2007, respectively; and $27,125 and $6,458 relate to the performance units and related distribution equivalent rights granted on January 17, 2008, respectively.

The following table reflects the aggregate payments that would have been made to each of the named executive officers under the 2005 Incentive Plan, the Long-Term Incentive Plan and related agreements in the event there was a Change of Control or their employment was terminated, each as of December 31, 2008.

Name	Change of Control	Termination for Death or Disability
Rene R. Joyce	$ 329,052	$ 329,052
Jeffrey J. McParland	213,040	213,040
Joe Bob Perkins	258,115	258,115
James W. Whalen	238,347	238,347
Michael A. Heim	249,764	249,764

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2008:

Name	Fees Earned or Paid in Cash	Stock Awards ($)(1)	All Other Compensation(4)	Total Compensation
Robert B. Evans (2) (3)	$ 64,000	$ 34,939	$ 6,585	$ 105,524
Chansoo Joung (2) (3)	49,000	34,939	6,585	90,524
Peter R. Kagan (2) (3)	49,000	34,939	6,585	90,524
Barry R. Pearl (2) (3)	84,000	34,939	6,585	125,524
William D. Sullivan (2) (3)	58,000	34,939	6,585	99,524

(1) Amounts represent expense recognized for financial statement reporting purposes in accordance with SFAS 123(R) with respect to stock awards for fiscal year 2008, disregarding any estimate of forfeitures related to service-based vesting conditions. No stock awards granted to the directors were forfeited during 2008. For a discussion of the assumptions and methodologies used to value the awards reported in these columns, see the discussion of stock awards contained in the Notes to Consolidated Financial Statements at Note 8 included in this Annual Report.

(2) Messrs. Evans, Joung, Kagan, Pearl and Sullivan each received 2,000 common units of the Partnership on March 25, 2008 in connection with their service on the Board of Directors of the Partnership's general partner. The grant date fair value of the 2,000 common units granted to each of these named individuals was $22.86, based on the closing price of the common units on the day prior to the grant date. During 2008, each of the directors received $6,585 in distributions on the common units of the Partnership that were awarded to them. The Partnership also recognized $6,585 of expense for each of the stock awards held by Messrs. Joung and Kagan.

(3) As of December 31, 2008, Mr. Evans held 13,900 common units, Mr. Joung and Kagan each held 4,000 common units, Mr. Pearl held 6,300 common units and Mr. Sullivan held 8,700 common units of the Partnership.

(4) For 2008 "All Other Compensation" consists of the distributions paid on common units of the Partnership from unit awards.

Narrative to Director Compensation Table

For 2008, each independent director receives an annual cash retainer of $34,000 and the chairman of the Audit Committee receives an additional annual retainer of $20,000. All of our independent directors receive $1,500 for each Board, Audit Committee and Conflicts Committee meeting attended. Payment of independent director fees is generally made twice annually, at the second regularly scheduled meeting of the Board and the final meeting of the Board for the fiscal year. All independent directors are reimbursed for out-of-pocket expenses incurred in attending Board and committee meetings.

A director who is also an employee receives no additional compensation for services as a director. Accordingly, the Summary Compensation Table reflects total compensation received by Messrs. Joyce and Whalen for services performed for us and our affiliates.

Director Long-term Equity Incentives. The Partnership made equity-based awards in March 2008 to the General Partners' nonmanagement and independent directors under the Partnership's long-term incentive plan. These awards were determined by Targa Investments and approved by the Board. Each of these directors received an initial award of 2,000 restricted units, which will settle with the delivery of Partnership common units. The Partnership has made similar grants under its long-term incentive plan to Targa's independent directors. All of these awards are subject to three-year vesting, without a performance condition and vest ratably on each anniversary of the grant. The awards are intended to align the long-term interests of executive officers and directors of the General Partner with those of the Partnership's unitholders. The independent and non-management directors of the General Partner and the independent directors of Targa Investments currently participate in the Partnership's plan.

Changes for 2009

Director Long-term Equity Incentives. In January 2009, each of the General Partners' nonmanagement and independent directors received an award of 4,000 restricted units under the Partnership's long-term incentive plan, which will settle with the delivery of Partnership common units. The Partnership has made similar grants under its long-term incentive plan to Targa's independent directors.

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

The following table sets forth the beneficial ownership of our units as of February 25, 2009 held by:

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

Name of Beneficial Owner (1)	Targa Resources Partners LP: Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned (6)	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common and Subordinated Units Beneficially Owned	Targa Resources Investments Inc.: Series B Preferred Stock	Restricted Common Stock	Percentage of Series B Preferred Stock Beneficially Owned	Percentage of Restricted Common Stock Beneficially Owned
Targa Resources Investments Inc. (2)	-	*	11,528,231	100.00%	24.9%	-	-	-	-
Lehman Brothers Holdings Inc. (3)	2,619,219	7.6%			5.7%	-	-	-	-
LaBranche Structured Products LLC (4)	2,510,920	7.2%			5.4%	-	-	-	-
Rene R. Joyce	81,000	*	295,678	2.56%	*	56,208	1,277,634 (7)	*	15.9%
Joe Bob Perkins	32,100	*	248,996	2.16%	*	47,632	1,071,154 (8)	*	13.5%
Michael A. Heim	8,000	*	235,415	2.04%	*	39,192	1,071,154 (8)	*	13.5%
Jeffrey J. McParland	16,500	*	209,512	1.82%	*	32,856	973,056 (9)	*	12.3%
James W. Whalen	111,152	*	165,365	1.43%	*	14,978	875,525(10)	*	11.3%
Chansoo Joung (5)	8,000	*	-	*	*	-	-	-	-
Peter R. Kagan (5)	8,000	*	-	*	*	-	-	-	-
Robert B. Evans	17,900	*	-	*	*	-	-	-	-
Barry R. Pearl	10,300	*	-	*	*	-	-	-	-
William D. Sullivan	12,700	*	-	*	*	-	-	-	-
All directors and executive officers as a group (12 persons)	292,252	*	1,551,157	13.46%	4.0%	241,114	7,226,752(11)	3.8%	72.6%

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1000 Louisiana, Suite 4300, Houston, Texas 77002. The nature of the beneficial ownership for all the equitysecurities is sole voting and investment power.

(2) The units attributed to Targa Resources Investments Inc. are held by two indirect wholly-owned subsidiaries, Targa GP Inc. and Targa LP Inc.

(3) Lehman Brothers Holdings Inc. beneficially owns 1,775,219 common units, of which Lehman Brothers Inc. beneficially owns 1,295,919 common units (which includes 805,919 common unitsdirectly held by Lehman Brothers Inc. and 490,000 common units directly held by Lehman Brothers MLP Partners LP) and Lehman Brothers MLP Opportunity Fund LP beneficially owns 479,300 common units. Lehman Brothers Inc. is wholly-owned by Lehman Brothers Holdings Inc. The address for Lehman Brothers Holdings Inc. and its affiliates is 745 Seventh Avenue, New York, New York 10019.

(4) LaBranche Structured Products LLC beneficially owns 2,510,920 common units. The address for LaBranche Structured Products LLC is 33 Whitehall Street, New York, New York 10004.

(5) Warburg Pincus Private Equity VIII, L.P., a Delaware limited partnership and two affiliated partnerships ("WP VIII") and Warburg Pincus Private Equity IX, L.P., a Delaware limited partnership ("WP IX"), in the aggregate own approximately 79% of Targa Resources Investments Inc. The general partner of WP VIII is Warburg Pincus Partners, LLC, a New York limited liability company ("WP Partners LLC") and the general partner of WP IX is Warburg Pincus IX, LLC, a New York limited liability company, of which WP Partners LLC is the sole member. Warburg Pincus & Co., a New York general partnership ("WP") is the managing member of WP Partners LLC. WP VIII and WP IX are managed by Warburg Pincus LLC, a New York limited liability company ("WP LLC"). The address of the Warburg Pincus entities is 466 Lexington Avenue, New York, New York 10017. Messrs. Kagan and Joung, directors of Targa Resources Partners LP, are Partners of WP and Managing Directors and Members of WP LLC. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members and Co-Presidents of WP LLC and may be deemed to control the Warburg Pincus entities. Messrs. Joung, Kagan, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.

(6) The subordinated units of the Partnership presented as being beneficially owned by our directors and executive officers represent the number of units held indirectly by Targa Resources Investments Inc. that are attributable to such directors and officers based on their ownership of equity interests in Targa Resources Investments Inc. Targa Resources Investments Inc. indirectly holds all 11,528,231 subordinated units of the Partnership.

(7) Of this amount, 452,209 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(8) Of this amount, 369,600 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(9) Of this amount, 321,770 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(10) Of this amount, 343,509 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.
(11) Of this amount, 2,385,143 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table sets forth certain information as of December 31, 2008 regarding the Partnership's long-term incentive plan, under which the Partnership's common units are authorized for issuance to employees, consultants and directors of the Partnership, its general partner and their affiliates. The Partnership's sole equity compensation plan is its long-term incentive plan, which was approved by its partners prior to its initial public offering.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	-	$ -	1,648,000
Equity compensation plans not approved by security holders	-	-	-
Total	-	$ -	1,648,000

Generally, awards of restricted units under our long-term incentive plan are subject to vesting over time as determined by our Compensation Committee and, prior to vesting, are subject to forfeiture. Long-term incentive plan awards may vest in other circumstances, as approved by the Compensation Committee and reflected in an award agreement. Restricted common units are issued, subject to vesting, on the date of grant. The Compensation Committee may provide that distributions on restricted units are subject to vesting and forfeiture provisions, in which case such distributions would be held, without interest, until they vest or are forfeited.

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

Our general partner and its affiliates own 11,528,231 subordinated units representing an aggregate 24.5% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us and the incentive distribution rights.

Distributions and Payments to Our General Partner and its Affiliates

The following table summarizes the distributions and payments made by us to our general partner and its affiliates in connection with our formation and to be made to us by our general partner and its affiliates in connection with our ongoing operation and any liquidation of us. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational Stage

Distributions of available cash to our general partner And its affiliates	We will generally make cash distributions 98% to our limited partner unitholders pro rata, including our general partner and its affiliates, as the holders of 11,528,231 subordinated units and 2% to our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $1.3 million on their general partner units and $15.6 million on their subordinated units.
Payments to our general partner and its affiliates	We reimburse Targa for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit. See "— Omnibus Agreement — Reimbursement of Operating and General and Administrative Expense."
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements Governing the Transactions

We and other parties entered into the various documents and agreements that effected our initial IPO transactions in February 2007 and the October 2007 offering transactions, including the vesting of assets in and the assumption of liabilities by, us and our subsidiaries and the application of the proceeds of the IPO and the October 2007 offering. These agreements were not the result of arm's-length negotiations and they or any of the transactions that they provide for, may not have been effected on terms at least as favorable to the parties to these agreements as they could have obtained from unaffiliated third parties. All of the transaction expenses incurred in connection with these transactions, including the expenses associated with transferring assets into our subsidiaries, were paid from the proceeds of the IPO and the October 2007 offering.

Purchase and Sale Agreement

On September 18, 2007, we entered into a purchase and sale agreement (the "Purchase Agreement") with Targa pursuant to which we acquired the SAOU and LOU Systems for aggregate consideration of $705 million, subject to certain adjustments, consisting of $697.6 million in cash and the issuance to our general partner of 275,511 general partner units, enabling our general partner to maintain its general partner interest in us. On September 25 and 26, 2007, Targa completed transactions that terminated certain out of the money NGL hedges associated with the SAOU and LOU Systems and entered into new hedges for approximately the same volume and term at then current market prices. Pursuant to the Purchase Agreement, these hedging transactions resulted in a $24.2 million increase to the purchase price we paid to Targa for the SAOU and LOU Systems. Pursuant to the Purchase Agreement, Targa agreed to indemnify us from and against (i) all losses that we incur arising from any breach of Targa's representations, warranties or covenants in the Purchase Agreement, (ii) certain environmental matters and (iii) certain litigation matters. We agreed to indemnify Targa from and against all losses that it incurs arising from or out of (i) the business or operations of Targa Resources Texas GP LLC, Targa Texas, Targa Louisiana and Targa Louisiana Intrastate LLC (whether relating to periods prior to or after the closing of the acquisition of the SAOU and LOU Systems) to the extent such losses are not matters for which Targa has indemnified us or (ii) any breach of our representations, warranties or covenants in the Purchase Agreement. Certain of Targa's indemnification obligations are subject to an aggregate deductible of $10 million and a cap equal to $80 million. In addition, the parties' reciprocal indemnification obligations for certain tax liability and losses are not subject to the deductible and cap. The acquisition closed on October 24, 2007.

On November 20, 2007, after the underwriters of the October 2007 offering exercised their option to purchase additional shares, we settled with Targa their purchase of an additional 37,062 general partner units allowing Targa to maintain its 2% general partner interest in us. In December 2007, the adjustments to the purchase price of the SAOU and LOU Systems resulted in an additional $0.8 million being paid to Targa.

Omnibus Agreement

Concurrently with the closing of the acquisition of the SAOU and LOU Systems, we amended and restated our Omnibus Agreement (as amended and restated, the "Omnibus Agreement") with Targa, our general partner and others that addresses the reimbursement of our general partner for costs incurred on our behalf, competition and indemnification matters. Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions described below, are terminable by Targa at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a Change of Control of us or our general partner.

Reimbursement of Operating and General and Administrative Expense

Under the terms of the Omnibus Agreement, we reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel and for the provision of various general and administrative services for our benefit. With respect to the North Texas System, we reimburse Targa for the following expenses:

- general and administrative expenses, which are capped at $5 million annually for three years ending February 2010, subject to increases based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of our conflicts committee; thereafter, our general partner will determine the general and administrative expenses to be allocated to us in accordance with our partnership agreement; and

- operations and certain direct expenses, which are not subject to the $5 million cap for general and administrative expenses.

With respect to the SAOU and LOU Systems, we will reimburse Targa for the following expenses:

- general and administrative expenses, which are not capped, allocated to the SAOU and LOU systems according to Targa’s allocation practice; and

- operating and certain direct expenses, which are not capped.

Pursuant to these arrangements, Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We reimburse Targa for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits.

General and administrative costs will continue to be allocated to the SAOU and LOU Systems according to Targa’s allocation practice.

Competition

Targa is not restricted, under either our partnership agreement or the Omnibus Agreement, from competing with us. Targa may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification

Under the Omnibus Agreement, Targa indemnifies us until February 14, 2010 against certain potential environmental claims, losses and expenses associated with the operation of the North Texas System and occurring before February 14, 2007 that are not reserved on the books of the Predecessor Business of the North Texas System as of February 14, 2007. Targa’s maximum liability for this indemnification obligation does not exceed $10.0 million and Targa does not have any obligation under this indemnification until our aggregate losses exceed $250,000. We have agreed to indemnify Targa against environmental liabilities related to the North Texas System arising or occurring after the closing date of this offering.

Additionally, Targa indemnifies us for losses attributable to rights-of-way, certain consents or governmental permits, preclosing litigation relating to the North Texas System and income taxes attributable to pre-IPO operations that are not reserved on the books of the Predecessor Business of the North Texas System as of February 14, 2007. Targa does not have any obligation under these indemnifications until our aggregate losses exceed $250,000. We will indemnify Targa for all losses attributable to the post-IPO operations of the North Texas System. Targa’s obligations under this additional indemnification survive until February 14, 2010, except that the indemnification for income tax liabilities will terminate upon the expiration of the applicable statute of limitations.

Contracts with Affiliates

NGL and Condensate Purchase Agreement for the North Texas System. We have entered into an NGL and high pressure condensate purchase agreement pursuant to which (i) we are obligated to sell all volumes of NGLs (other than high-pressure condensate) that we own or control to Targa Liquids Marketing and Trade (“TLMT”) and (ii) we have the right to sell to TLMT or third parties the volumes of high-pressure condensate that we own or control, in each case at a price based on the prevailing market price less transportation, fractionation and certain other fees. This agreement has an initial term of 15 years and automatically extends for a term of five years, unless the agreement is otherwise terminated by either party. Furthermore, either party may elect to terminate the agreement if either party ceases to be an affiliate of Targa.

NGL Purchase Agreements for the SAOU and LOU Systems. The SAOU System has entered into an NGL purchase agreement pursuant to which it is obligated to sell all volumes of mixed NGLs or raw product, which it owns or controls to TLMT at a price based on either TLMT's sales price to third parties or the prevailing market price, less transportation, fractionation and certain other fees. The LOU System also has entered into an NGL purchase agreement pursuant to which (i) it has the right to sell to TLMT the volumes of raw product that it owns or controls at a commercially reasonable price agreed by the parties and (ii) it is obligated to sell all volumes of fractionated NGL components that it owns or controls at a price based on TLMT's sales price to third parties or the prevailing market price, less transportation, fractionation and certain other fees. Both NGL purchase agreements have an initial term of one year and automatically extend for additional terms of one year, unless the agreements are otherwise terminated by either party.

Natural Gas Purchase Agreements. Both the North Texas System and the SAOU and LOU Systems have entered into market based natural gas purchase agreements. These agreements have an initial term of 15 years and automatically extend for a term of five years, unless the agreements are otherwise terminated by either party. Furthermore, either party may elect to terminate the agreements if either party ceases to be an affiliate of Targa. In addition, Targa manages the SAOU and LOU Systems' natural gas sales to third parties under contracts that remain in the name of the SAOU and LOU Systems.

Indemnification Agreements. In February 2007, Targa Resources GP LLC, our general partner and we entered into Indemnification Agreements (each, an "Indemnification Agreement") with each independent director of Targa Resources GP LLC (each, an "Indemnitee"). Each Indemnification agreement provides that each of the Partnership and Targa Resources GP LLC will indemnify and hold harmless each Indemnitee against Expenses (as defined in the Indemnification Agreement) to the fullest extent permitted or authorized by law, including the Delaware Revised Uniform Limited Partnership Act and the Delaware Limited Liability Company Act in effect on the date of the agreement or as such laws may be amended to provide more advantageous rights to the Indemnitee. If such indemnification is unavailable as a result of a court decision and if we or Targa Resources GP LLC is jointly liable in the proceeding with the Indemnitee, we and Targa Resources GP LLC will contribute funds to the Indemnitee for his Expenses in proportion to relative benefit and fault of the Partnership or Targa Resources GP LLC on the one hand and Indemnitee on the other in the transaction giving rise to the proceeding.

Each Indemnification Agreement also provides that we and Targa Resources GP LLC will indemnify and hold harmless the Indemnitee against Expenses incurred for actions taken as a director or officer of the Partnership or Targa Resources GP LLC or for serving at the request of the Partnership or Targa Resources GP LLC as a director or officer or another position at another corporation or enterprise, as the case may be, but only if no final and non-appealable judgment has been entered by a court determining that, in respect of the matter for which the Indemnitee is seeking indemnification, the Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal proceeding, the Indemnitee acted with knowledge that the Indemnitee's conduct was unlawful. The Indemnification Agreement also provides that we and Targa Resources GP LLC must advance payment of certain Expenses to the Indemnitee, including fees of counsel, subject to receipt of an undertaking from the Indemnitee to return such advance if it is it is ultimately determined that the Indemnitee is not entitled to indemnification.

In February 2007, Targa Resources Investments Inc., the indirect holder of all of our subordinated units, entered into Indemnification Agreements (each, a "Parent Indemnification Agreement") with each director and officer of Targa (each, a "Parent Indemnitee"), including Messrs. Joyce, Whalen, Kagan and Joung who serve as directors and/or officers of our general partner. Each Parent Indemnification Agreement provides that Targa Resources Investments Inc. will indemnify and hold harmless each Parent Indemnitee for Expenses (as defined in the Parent Indemnification Agreement) to the fullest extent permitted or authorized by law, including the Delaware General Corporation Law, in effect on the date of the agreement or as it may be amended to provide more advantageous rights to the Parent Indemnitee. If such indemnification is unavailable as a result of a court decision and if Targa Resources Investments Inc. and the Parent Indemnitee are jointly liable in the proceeding, Targa Resources Investments Inc. will contribute funds to the Parent Indemnitee for his Expenses in proportion to relative benefit and fault of Targa Resources Investments Inc. and Parent Indemnitee in the transaction giving rise to the proceeding.

Each Indemnification Agreement also provides that Targa Resources Investments Inc. will indemnify the Parent Indemnitee for monetary damages for actions taken as a director or officer of Targa Resources Investments Inc. or for serving at Targa's request as a director or officer or another position at another corporation or enterprise, as the case may be but only if (i) the Parent Indemnitee acted in good faith and, in the case of conduct in his official capacity, in a manner he reasonably believed to be in the best interests of Targa Resources Investments Inc. and, in all other cases, not opposed to the best interests of Targa Resources Investments Inc. and (ii) in the case of a criminal proceeding, the Parent Indemnitee must have had no reasonable cause to believe that his conduct was unlawful. The Parent Indemnification Agreement also provides that Targa Resources Investments Inc. must advance payment of certain Expenses to the Parent Indemnitee, including fees of counsel, subject to receipt of an undertaking from the Parent Indemnitee to return such advance if it is it is ultimately determined that the Parent Indemnitee is not entitled to indemnification.

See "Item 1. Business—Our Relationship with Targa Resources, Inc." for information regarding our relationship with Targa.

Relationships with Warburg Pincus

Chansoo Joung and Peter Kagan, two of the directors of Targa, are Managing Directors of Warburg Pincus and are also directors of Broad Oak Energy, Inc. ("Broad Oak") from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus own a controlling interest in Broad Oak. We purchased $4.8 million of product from Broad Oak during 2008. We had no commercial transactions prior to 2008 with Broad Oak. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationships with Noble Energy

Chris Tong, one of the directors of Targa, is a Senior Vice President and Chief Financial Officer of Noble Energy, Inc. ("Noble") from whom we buy certain commodity products. We had net purchases of $0.1 million, $0.1 million and $1.7 million of natural gas from Noble during 2008, 2007 and 2006. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including Targa) on the one hand and our partnership and our limited partners, on the other hand. The directors and officers of Targa Resources GP LLC have fiduciary duties to manage Targa and our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand and us or any other partner, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that modify and limit our general partner's fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions taken that, without those limitations, might constitute breaches of fiduciary duty.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third or fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement provides that someone act in good faith, it requires that person to believe he is acting in the best interests of the partnership.

Review, Approval or Ratification of Transactions with Related Persons

If a conflict or potential conflict of interest arises between our general partner and its affiliates (including Targa) on the one hand and our partnership and our limited partners, on the other hand, the resolution of any such conflict or potential conflict is addressed as described under "—Conflicts of Interest."

Pursuant to Targa's Code of Conduct, our officers and directors are required to abandon or forfeit any activity or interest that creates a conflict of interest between them and Targa or any of its subsidiaries, unless the conflict is pre-approved by the Board of Directors.

Director Independence

The NASDAQ Stock Market LLC does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee. Our general partner has a standing Audit Committee that consists of three directors: Messrs. Evans, Pearl and Sullivan. The board of directors of our general partner has affirmatively determined that Messrs. Evans, Pearl and Sullivan are independent as described in the rules of The NASDAQ Stock Market LLC and the Exchange Act for purposes of serving on the board of directors and the Audit Committee, respectively. Although the board of directors of our general partner has made no formal determination as to the independence of our other directors because we are not subject to majority independence requirements, it is likely that Messrs. Kagan and Joung would be determined to be independent for purposes of serving on the board of directors. Messrs. Joyce, Whalen, Kagan and Joung would not be independent for purposes of serving on the Audit Committee.

Item 14. *Principal Accountant Fees and Services*

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we were billed by PricewaterhouseCoopers for independent auditing, tax and related services for each of the last two fiscal years:

	Year Ended December 31,	
	2008	2007
	(In thousands)	
Audit Fees (1)	$ 1,219.6	$ 2,267.5
Tax Fees (2)	534.2	303.8
All Other Fees (3)	-	-
	$ 1,753.8	$ 2,571.3

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this Annual Report on Form 10-K.

(2) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements.

(3) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above.

All services provided by our independent auditor are subject to pre-approval by our audit committee. The Audit Committee is informed of each engagement of the independent auditor to provide services under the policy. The Audit Committee has approved the use of PricewaterhouseCoopers as our independent principal accountant.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) *Financial Statements*

Our Consolidated Financial Statements are included under Part II, Item 8 of the annual Report. For a listing of these statements and accompanying footnotes, see *"Index to Financial Statements"* Page F-1 of this Annual Report.

(a)(2) *Financial Statement Schedules*

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financials statements or notes thereto.

(a)(3) *Exhibits*

2.1**	Purchase and Sale Agreement, dated as of September 18, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 21, 2007 (File No. 001-33303)).
2.2	Amendment to Purchase and Sale Agreement, dated October 1, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
3.4	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.5	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.6	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).

4.1 Specimen Unit Certificate representing common units (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).

4.2 Indenture dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 18, 2008 (File No. 001-33303)).

4.3 Registration Rights Agreement dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed June 18, 2008 (File No. 001-33303)).

10.1 Credit Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, as Borrower, Bank of America, N.A., as Administrative Agent, Wachovia Bank, N.A., as Syndication Agent, Merrill Lynch Capital, Royal Bank of Canada and The Royal Bank of Scotland PLC, as Co-Documentation Agents and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).

10.2 Commitment Increase Supplement, dated October 24, 2007, by and among Targa Resources Partners LP, Bank of America, N.A. and the parties signatory thereto as the Increasing Lenders and the New Lenders (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).

10.3 First Amendment to Credit Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Bank of America, N.A. and each Lender party thereto (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).

10.4 Commitment Increase Supplement, dated June 18, 2008, by and among Targa Resources Partners LP, Bank of America, N.A. and other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 24, 2008 (File No. 001-33303)).

10.5 Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa North Texas GP LLC and Targa North Texas LP (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).

10.6 Contribution, Conveyance and Assumption Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources Holdings LP, Targa TX LLC, Targa TX PS LP, Targa LA LLC, Targa LA PS LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).

10.7 Amended and Restated Omnibus Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).

10.8+ Targa Resources Partners Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).

10.9+ Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).

10.10+* Amendment to Targa Resources Partners LP Long-Term Incentive Plan dated December 18, 2008.

10.11+ Form of Restricted Unit Grant Agreement (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).

10.12+* Form of Performance Unit Grant Agreement (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 28, 2009 (File No. 001-33303)).

10.13+* Targa Resources Investments Inc. 2008 Annual Incentive Compensation Plan

10.14+* Targa Resources Investments Inc. 2009 Annual Incentive Compensation Plan

10.15 Gas Gathering and Purchase Agreement by and between Burlington Resources Oil & Gas Company LP, Burlington Resources Trading Inc. and Targa Midstream Services Limited Partnership (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 8, 2007 (File No. 333-138747)).

10.16 Natural Gas Purchase Agreement, effective January 1, 2007, by and between Targa Gas Marketing LLC (Buyer) and Targa North Texas LP (Seller) (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP's Registration Statement on Form S-1 filed October 1, 2007 (File No. 333-146436)).

10.17 NGL and Condensate Purchase Agreement, effective January 1, 2007, by and between Targa North Texas LP (Seller) and Targa Liquids Marketing and Trade (Buyer) (incorporated by reference to Exhibit 10.12 to Targa Resources Partners LP's Registration Statement on Form S-1 filed October 1, 2007 (File No. 333-146436)).

10.18 Product Purchase Agreement, effective January 1, 2007, by and between Targa Louisiana Field Services LLC (Seller) and Targa Liquids Marketing and Trade (Buyer) (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.19 Raw Product Purchase Agreement, effective January 1, 2007, by and between Targa Texas Field Services LP (Seller) and Targa Liquids Marketing and Trade (Buyer) (incorporated by reference to Exhibit 10.14 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.20 Amended and Restated Natural Gas Sales Agreement, effective December 1, 2005, by and between Targa Louisiana Field Services LLC (Buyer) and Targa Gas Marketing LLC (Seller) (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.21 Amended and Restated Natural Gas Purchase Agreement, effective December 1, 2005, by and between Targa Gas Marketing LLC (Buyer) and Targa Louisiana Field Services LLC (Seller) (incorporated by reference to Exhibit 10.16 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.22 Amended and Restated Natural Gas Purchase Agreement, effective December 1, 2005, by and between Targa Gas Marketing LLC (Buyer) and Targa Texas Field Services LP (Seller) (incorporated by reference to Exhibit 10.17 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.23+ Targa Resources Partners LP Indemnification Agreement for Barry R. Pearl dated February 14, 2007 (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).

10.24+	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007 (incorporated by reference to Exhibit 10.12 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.25+	Targa Resources Partners LP Indemnification Agreement for Williams D. Sullivan dated February 14, 2007 (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.26	Purchase Agreement dated June 12, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 18, 2008 (File No. 001-33303)).
21.1*	Subsidiaries of Targa Resources Partners LP
23.1*	Consent of Independent Registered Public Accounting Firm
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1*	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

** Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted exhibit or Schedule to the SEC upon request.

\+ Management contract or compensatory plan or arrangement.

SIGNATURES

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

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC, its general partner

By: */s/ John Robert Sparger*
John Robert Sparger
Senior Vice President and
Chief Accounting Officer
(Principal Accounting Officer)

Date: February 26, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 26, 2009.

Signature	Title (Position with Targa Resources GP LLC)
/s/ Rene R. Joyce Rene R. Joyce	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Jeffrey J. McParland Jeffrey J. McParland	Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ John Robert Sparger John Robert Sparger	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ James W. Whalen James W. Whalen	President —Finance and Administration and Director
/s/ Peter R. Kagan Peter R. Kagan	Director
/s/ Chansoo Joung Chansoo Joung	Director
/s/ Barry R. Pearl Barry R. Pearl	Director
/s/ Robert B. Evans Robert B. Evans	Director
/s/ William D. Sullivan William D. Sullivan	Director

INDEX TO FINANCIAL STATEMENTS

TARGA RESOURCES PARTNERS LP AUDITED COMBINED CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Targa Resources GP LLC, the general partner of the Partnership, is responsible for establishing and maintaining adequate internal control over financial reporting. Our 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.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

The management of Targa Resources GP LLC has used the framework set forth in the report entitled "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the Partnership's internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership's internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of the Partnerships's internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

/s/ Rene R. Joyce
Rene R. Joyce
Chief Executive Officer of Targa Resources
GP LLC, the general partner of Targa Resources
Partners LP (Principal Executive Officer)

/s/ Jeffrey J. McParland
Jeffrey J. McParland
Executive Vice President, Chief Financial Officer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP
(Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income (loss), of changes in partners' capital/net parent investment and of cash flows present fairly, in all material respects, the financial position of Targa Resources Partners LP and its subsidiaries (the "Partnership") at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also 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 (COSO). The Partnership's management is responsible for these financial statements, 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 opinions on these financial statements and on the Partnership's internal control over financial reporting based on our audits (which was an integrated audit in 2008). 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 6 to the consolidated financial statements, the Partnership has engaged in significant transactions with other subsidiaries of its parent company, Targa Resources, Inc., a related party.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

/s/ PricewaterhouseCoopers

Houston, Texas
February 25, 2009

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 81,768	$ 50,994
Receivables from third parties	58,355	59,346
Receivables from affiliated companies	22,295	87,547
Inventory	987	1,624
Assets from risk management activities	91,816	8,695
Other current assets	289	269
Total current assets	255,510	208,475
Property, plant and equipment, at cost	1,492,726	1,433,955
Accumulated depreciation	(248,389)	(174,361)
Property, plant and equipment, net	1,244,337	1,259,594
Debt issue costs	10,524	6,588
Long-term assets from risk management activities	68,296	3,040
Other assets	2,239	2,275
Total assets	$1,580,906	$1,479,972
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 8,649	$ 5,693
Accrued liabilities	86,191	142,836
Liabilities from risk management activities	11,664	44,003
Total current liabilities	106,504	192,532
Long-term debt	696,845	626,300
Long term liabilities from risk management activities	9,679	43,109
Deferred income taxes	1,959	559
Other long-term liabilities	3,555	3,266
Commitments and contingencies (Note 11)		
Partners' capital:		
Common unitholders (34,652,000 and 34,636,000 units issued and outstanding as of December 31, 2008 and 2007)	769,921	770,207
Subordinated unitholders (11,528,231 units issued and outstanding as of December 31, 2008 and 2007)	(85,185)	(84,999)
General partner (942,455 and 942,128 units issued and outstanding as of December 31, 2008 and 2007)	5,556	4,234
Accumulated other comprehensive income (loss)	72,072	(75,236)
Total partners' capital	762,364	614,206
Total liabilities and partners' capital	$1,580,906	$1,479,972

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2008	2007	2006
	(In thousands, except per unit amounts)		
Revenues from third parties	$ 848,725	$ 630,773	$ 951,936
Revenues from affiliates	1,225,393	1,030,696	786,589
Total operating revenues	2,074,118	1,661,469	1,738,525
Costs and expenses:			
Product purchases from third parties	1,479,061	1,215,733	1,194,751
Product purchases from affiliates	323,970	191,064	322,917
Operating expenses	55,325	50,931	49,075
Depreciation and amortization expense	74,274	71,756	69,957
General and administrative expense	22,392	18,927	16,063
Casualty loss	167	-	-
Gain on sale of assets	(105)	(296)	-
	1,955,084	1,548,115	1,652,763
Income from operations	119,034	113,354	85,762
Other income (expense):			
Interest expense, net	(38,274)	(21,998)	-
Interest expense allocated from Parent	-	(19,436)	(88,025)
Gain on debt extinguishment	13,061	-	-
Gain (loss) on mark-to-market derivative instruments	(991)	(30,221)	16,756
Other	64	30	-
Income before taxes	92,894	41,729	14,493
Deferred income tax expense	(1,400)	(1,479)	(2,926)
Net income	91,494	40,250	$ 11,567
Less: Net income allocable to predecessor operations	-	12,184	
Net income allocable to partners	91,494	28,066	
Net income attributable to general partner interests	7,049	561	
Net income available to limited partners	$ 84,445	$ 27,505	
Basic and diluted net income per limited partner unit	$ 1.83	$ 0.81	
Basic and diluted average limited partner units outstanding	46,177	34,002	

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Net income	$ 91,494	$ 40,250	$ 11,567
Other comprehensive income (loss):			
Commodity hedges:			
Change in fair value	130,002	(105,584)	36,937
Reclassification adjustment for settled periods	33,650	993	(822)
Related income taxes	-	312	(312)
Interest rate hedges:			
Change in fair value	(19,037)	(1,689)	1,267
Reclassification adjustment for settled periods	2,693	(232)	(488)
Other comprehensive income (loss)	147,308	(106,200)	36,582
Comprehensive income (loss)	$ 238,802	$ (65,950)	$ 48,149

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL / NET PARENT INVESTMENT

	Partners' Capital			Accumulated Other		
	Limited Partners		General	Comprehensive	Net Parent	
	Common	Subordinated	Partner	Income (Loss)	Investment	Total
	(In thousands)					
Balance, December 31, 2005	$ -	$ -	$ -	$ (5,618)	$ 286,841	$ 281,223
Distributions to Parent	-	-	-	-	(83,459)	(83,459)
Net income	-	-	-	-	11,567	11,567
Other comprehensive income	-	-	-	36,582	-	36,582
Balance, December 31, 2006	-	-	-	30,964	214,949	245,913
Net income attributable to predecessor operations:						
For the period January 1, 2007 to February 13, 2007						
for North Texas	-	-	-	-	(6,861)	(6,861)
For the period January 1, 2007 to October 23, 2007						
for SAOU/LOU	-	-	-	-	19,045	19,045
Net income attributable to post MLP ownership	19,063	8,442	561		-	28,066
Other contributions associated with North Texas System	-	-	-	-	218,993	218,993
Other contributions associated with SAOU/LOU System	-	-	-	-	195,960	195,960
Book value of net assets contributed by Targa Resources, Inc.	-	376,351	20,554	-	(396,905)	-
Book value of net assets transferred via common control						
from Targa Resources, Inc. to the Partnership	-	232,420	12,761	-	(245,181)	-
Distribution to Targa Resources, Inc. for assets transferred						
under common control	-	(692,486)	(37,416)	-	-	(729,902)
Issuance of units to public (including underwriter						
over-allotment), net of offering and other costs	771,835	-	8,398	-	-	780,233
Amortization of equity awards	180	-	-	-	-	180
Other comprehensive loss	-	-	-	(106,200)	-	(106,200)
Distributions to unitholders	(20,871)	(9,726)	(624)	-	-	(31,221)
Balance, December 31, 2007	770,207	(84,999)	4,234	(75,236)	-	614,206
Contributions	-	-	8	-	-	8
Amortization of equity awards	280	-	-	-	-	280
Other comprehensive income	-	-	-	147,308	-	147,308
Net income	63,362	21,083	7,049	-	-	91,494
Distributions to unitholders	(63,928)	(21,269)	(5,735)	-	-	(90,932)
Balance, December 31, 2008	$ 769,921	$ (85,185)	$ 5,556	$ 72,072	$ -	$ 762,364

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Cash flows from operating activities			
Net income	$ 91,494	$ 40,250	$ 11,567
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization in interest expense	2,116	1,805	6,246
Amortization in general and administrative expense	280	180	-
Depreciation and other amortization expense	74,274	71,756	69,957
Accretion of asset retirement obligations	231	342	245
Deferred income tax expense	1,400	1,479	2,926
Risk management activities	(63,973)	30,751	(18,297)
Gain on debt extinguishment	(13,061)	-	-
Gain on sale of assets	(105)	(296)	-
Changes in operating assets and liabilities:			
Receivables and other assets	63,698	89,487	79,573
Inventory	637	(666)	1,373
Accounts payable and other liabilities	(61,756)	35,392	(29,156)
Net cash provided by operating activities	95,235	270,480	124,434
Cash flows from investing activities			
Purchases of property, plant and equipment	(51,169)	(41,088)	(32,575)
Other, net	167	372	(317)
Net cash used in investing activities	(51,002)	(40,716)	(32,892)
Cash flows from financing activities			
Proceeds from borrowings under credit facility	185,265	721,300	-
Repayments on credit facility	(323,800)	(95,000)	-
Proceeds from issuance of senior notes	250,000	-	-
Repurchases of senior notes	(26,832)	-	-
Repayment of affiliated indebtedness	-	(665,692)	-
Proceeds from equity offerings	-	777,471	-
Distributions to unitholders	(90,932)	(31,221)	-
General partner contributions	8	-	-
Costs incurred in connection with public offerings	(89)	(4,640)	-
Costs incurred in connection with financing arrangements	(7,079)	(7,491)	-
Deemed Parent distributions	-	(873,497)	(91,542)
Net cash used in financing activities	(13,459)	(178,770)	(91,542)
Net change in cash and cash equivalents	30,774	50,994	-
Cash and cash equivalents, beginning of year	50,994	-	-
Cash and cash equivalents, end of year	$ 81,768	$ 50,994	$ -
Supplemental cash flow information:			
Net settlement of allocated indebtedness and debt issue costs	$ -	$ 301,801	$ 330
Net contribution of affiliated receivables	-	184,462	-
Noncash long-term debt allocation of payments from Parent	-	59,400	5,979
Interest paid	29,271	15,453	-
Debt issue costs allocated from Parent	-	-	5,903

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Operations

Targa Resources Partners LP, together with our subsidiaries (“we,” “us,” “our” or the “Partnership”), is a publicly traded Delaware limited partnership formed on October 26, 2006 by Targa Resources, Inc. (“Targa” or “Parent”), a leading provider of midstream natural gas and NGL services in the United States, to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are engaged in the business of gathering, compressing, treating, processing and selling natural gas and fractionating and selling natural gas liquids (“NGLs”) and NGL products. We currently operate in the Fort Worth Basin/Bend Arch in North Texas (the “Fort Worth Basin”), the Permian Basin of West Texas and in Southwest Louisiana.

Initial Public Offering

On February 14, 2007, we completed our initial public offering (“IPO”) of common units representing limited partner interests in the Partnership. In the IPO, we issued 19,320,000 common units at a price of $21.00 per unit. We used the net proceeds of the IPO (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) to pay expenses related to the IPO and our new senior secured revolving credit facility (“credit facility”) and to repay approximately $371.2 million of our outstanding allocated indebtedness. Concurrent with the IPO, Targa contributed its interest in Targa North Texas GP LLC and Targa North Texas LP (collectively the “North Texas System”) to us. Targa indirectly received a 2% general partnership interest in us (629,555 general partner units), incentive distribution rights, and a limited partnership interest in us (represented by 11,528,231 subordinated units). Our common units are listed on The NASDAQ Stock Market LLC under the symbol “NGLS.”

Acquisition of SAOU and LOU Systems

On October 24, 2007, we completed the purchase from Targa of its ownership interests in Targa Texas Field Services LP, (the “SAOU System”), and Targa Louisiana Field Services LLC (the “LOU System”). This acquisition consisted of the SAOU System’s natural gas gathering and processing businesses located in the Permian Basin of West Texas and the LOU System’s natural gas gathering and processing businesses located in Southwest Louisiana. The total value of the transaction was approximately $706 million. In addition, we paid approximately $24.2 million to Targa for the termination of certain hedge transactions. Concurrent with the acquisition, we sold 13,500,000 common units representing limited partnership interests in us at a price of $26.87 per common unit ($25.796 per common unit after the underwriting discount). Total consideration paid by us to Targa consisted of cash of approximately $722.5 million and 312,246 general partner units issued to Targa to allow it to maintain its 2% general partner interest in us. On November 20, 2007, the underwriters exercised their option to purchase an additional 1,800,000 common units at the same $26.87 price per common unit. The net proceeds from the underwriters’ exercise were used to reduce borrowings under our credit facility by approximately $47 million.

Note 2—Basis of Presentation

The consolidated financial statements include our accounts and: (i) prior to October 24, 2007 the assets, liabilities and operations of the SAOU and LOU Systems; and (ii) prior to February 14, 2007 the assets, liabilities and operations of the North Texas System.

Targa’s conveyance to us of the North Texas System and our acquisition from Targa of the SAOU and LOU Systems has been accounted for as transfers of net assets between entities under common control. We recognize transfers of net assets between entities under common control at Targa’s basis in the net assets. In addition, transfers of net assets between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retroactively adjusted to furnish comparative information similar to the pooling method. The amount of the purchase price in excess of Targa’s basis in the net assets, if any, is recognized as a reduction to partners’ equity.

The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We refer to the operations, assets and liabilities of the North Texas System, the SAOU System and the LOU System, prior to our acquisition from Targa, collectively as our "predecessors." The consolidated financial statements of our predecessors have been prepared from the separate records maintained by Targa and may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessors had been operated as an unaffiliated entity. All significant intercompany balances and transactions have been eliminated. Certain reclassifications have been made to the previous years to conform to the 2008 presentation. Transactions between us and other Targa operations have been identified in the consolidated financial statements as transactions between affiliates.

We have been allocated general and administrative expenses incurred by the Parent in order to present financial statements on a stand-alone basis. See Note 10. All of the allocations are not necessarily indicative of the costs and expenses that would have resulted had we been operated as stand-alone entities.

Note 3—Significant Accounting Policies

Asset retirement obligations ("AROs"). AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the asset's acquisition, construction, development and/or normal operation. An ARO is initially measured at its estimated fair value. Upon initial recognition of an ARO, we record an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. The consolidated cost of the asset and the capitalized asset retirement obligation is depreciated using a systematic and rational allocation method over the period during which the long-lived asset is expected to provide benefits. After the initial period of ARO recognition, the ARO will change as a result of either the passage of time or revisions to the original estimates of either the amounts of estimated cash flows or their timing. Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Upon settlement, AROs will be extinguished by us at either the recorded amount or we will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost.

Cash and Cash Equivalents. Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Comprehensive Income. Comprehensive income includes net income and other comprehensive income, which includes unrealized gains and losses on derivative instruments that are designated as hedges.

Concentration of Credit Risk. Financial instruments which potentially subject us to concentrations of credit risk consist primarily of trade accounts receivable and commodity derivative instruments.

Trade Accounts Receivable. We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit, and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met.

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. In evaluating the level of established reserves, we make judgments regarding each party's ability to make required payments, economic events and other factors. As the financial condition of any party changes, circumstances develop or additional information becomes available, adjustments to an allowance for doubtful accounts may be required. We do not have an allowance for doubtful accounts as of December 31, 2008, and we have not recognized any bad debt expense for the three-year period then ended.

Commodity Derivative Instruments. As of December 31, 2008, affiliates of Goldman Sachs, Merrill Lynch and Barclays Bank accounted for 67%, 21% and 11% of our counterparty credit exposure related to commodity derivative instruments. Goldman Sachs, Merrill Lynch and Barclays Bank are major financial institutions, each possessing investment grade credit ratings, based upon minimum credit ratings assigned by Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies, Inc.

Debt Issue Costs. Costs incurred in connection with the issuance of long-term debt are capitalized and charged to interest expense over the term of the related debt.

Environmental Liabilities. Liabilities for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated.

Income Taxes. We are not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of our individual partners. In May 2006, Texas adopted a margin tax, consisting generally of a 1% tax on the amount by which total revenues exceed cost of goods sold, as apportioned to Texas. Accordingly, we have estimated our liability for this tax and it is presently recorded as a deferred tax liability.

We have determined that there are no significant uncertain tax positions requiring recognition in our financial statements as of December 31, 2008. There are no unrecognized tax benefits that, if recognized, would affect the effective rate, and there are no unrecognized tax benefits that are reasonably expected to increase or decrease in the next twelve months. We file tax returns in the United States Federal and several state jurisdictions, and are open to federal and state income tax examinations for years 2007 forward. Presently, no income tax examinations are underway, and none have been announced. No potential interest or penalties were recognized as of December 31, 2008.

Inventory Imbalance. Quantities of natural gas and/or NGLs over-delivered or under-delivered related to operational balancing agreements are recorded monthly as inventory or as a payable using weighted average prices as of the time the imbalance was created. Monthly, inventory imbalances receivable are valued at the lower of cost or market; inventory imbalances payable are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas or NGLs. Certain contracts require cash settlement of imbalances on a current basis. Under these contracts, imbalance cash-outs are recorded as a sale or purchase of natural gas, as appropriate.

Net Income per Limited Partner Unit. We compute earnings per unit using the Two-Class Method. The Two-Class Method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit using the Two-Class Method. Under the Two-Class Method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

The Two-Class Method does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our aggregate distributions for such period, the Two-Class Method does not have any impact on our calculation of earnings per limited partner unit.

Our net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner. Basic and diluted net income per limited partner unit is calculated by dividing limited partners' interest in net income, less general partner incentive distributions, by the applicable weighted average number of outstanding limited partner units during the period.

The calculation of net income per limited and subordinated partner unit for 2006 is not presented as we did not have any outstanding units until we completed our IPO on February 14, 2007. The calculation of basic and diluted net income per common and subordinated unit are the same for all periods presented as distributable cash flow was greater than net income for those periods and distributions to the subordinated unitholders have been equivalent to the distribution to the common unitholders for all quarters.

Price Risk Management (Hedging). All derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If a derivative qualifies for hedge accounting and is designated as a cash flow hedge, the effective portion of the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income ("OCI"), a component of partners' capital, and reclassified to earnings when the forecasted transaction occurs. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. At the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Hedge ineffectiveness is measured on a quarterly basis. Any ineffective portion of the unrealized gain or loss is reclassified to earnings in the current period.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument is terminated or ceases to be highly effective. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is no longer probable that a hedged forecasted transaction will occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

Property, Plant and Equipment. Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The estimated service lives of our functional asset groups are as follows:

Asset Group	Range of Years
Gas gathering systems and processing systems	15 to 25
Other property and equipment	3 to 7

Expenditures for maintenance and repairs are expensed as incurred. Expenditures to refurbish assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset.

Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. From time to time, we utilize consultants and other experts to assist us in assessing the remaining lives of the crude oil or natural gas production in the basins we serve.

We may capitalize certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs. Upon disposition or retirement of property, plant and equipment, any gain or loss is charged to operations.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. We continually monitor our businesses and the market and business environments to identify indicators that may suggest an asset may not be recoverable.

We evaluate an asset for recoverability by comparing the carrying value of the asset with the asset's expected future undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future undiscounted cash flows we recognize an impairment loss to write down the carrying amount of the asset to its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our Consolidated Statements of Operations.

Revenue Recognition. Our primary types of sales and service activities reported as operating revenues include:

- sales of natural gas, NGLs and condensate; and
- natural gas processing, from which we generate revenues through the compression, gathering, treating, and processing of natural gas.

We recognize revenues when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, if applicable, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectibility is reasonably assured.

For processing services, we receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, we receive either an agreed upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage based on index related prices for the natural gas and NGLs. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, we keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. Natural gas or NGLs that we receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee-based contracts, we receive a fee based on throughput volumes.

We generally report revenues gross in our Consolidated Statements of Operations. Except for fee-based contracts, we act as the principal in the transactions where we receive commodities, take title to the natural gas and NGLs, and incur the risks and rewards of ownership.

Segment Information. We operate in one segment only, the natural gas gathering and processing segment.

Unit-Based Employee Compensation. We award share-based compensation to directors in the form of restricted common units. Compensation expense on restricted common units is measured by the fair value of the award at the date of grant. Compensation expense is recognized in general and administrative expense over the requisite service period of each award. See Note 8.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the period. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues and operating and general and administrative costs (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from estimated amounts.

Accounting Pronouncements Recently Adopted

In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") 157, *"Fair Value Measurements."* SFAS 157 establishes a framework for measuring fair value and expands disclosures about fair value measurements. In February 2008, the FASB issued FASB Staff Position FAS 157-2, "*Effective Date of FASB Statement No. 157,"* which delayed the effective date of SFAS 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis, until January 1, 2009.

We have not yet conclusively determined the impact that our implementation of SFAS 157 will have on our non-financial assets and liabilities; however we do not anticipate it to significantly impact our consolidated financial statements. We adopted SFAS 157 with respect to financial assets and liabilities that are recognized on a recurring basis on January 1, 2008. Although the adoption of SFAS 157 did not materially impact our financial condition, results of operations, or cash flows, we are now required to provide additional disclosures as part of our financial statements. See Note 13.

In March 2008, the FASB issued SFAS 161, *"Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133."* SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133, *"Derivative Instruments and Hedging Activities*" and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Early adoption is encouraged. Our adoption of SFAS 161 as of December 31, 2008 did not impact our consolidated financial position, results of operations or cash flows. See Note 10.

Accounting Pronouncements Recently Issued

In December 2007, the FASB issued SFAS No. 141 (revised 2007), "*Business Combination.*" ("SFAS 141R"). SFAS 141R establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any noncontrolling interest in the acquiree and the goodwill acquired. SFAS 141R also establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. SFAS 141R is effective as of the beginning of an entity's fiscal year that begins after December 15, 2008. This new accounting standard will only impact how we account for business combinations on a prospective basis.

In March 2008, the FASB's Emerging Issues Task Force ("EITF") reached a consensus on EITF 07-4, *"Application of the Two - Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships."* EITF 07-4 improves the comparability of earnings per unit calculations for master limited partnerships ("MLPs") with incentive distribution rights ("IDRs") in accordance with Statement 128 and its related interpretations. Under EITF 07-4, when an MLP's current-period earnings are in excess of cash distributions and the IDRs are a separate limited partner interest, undistributed earnings should be allocated to the general partner, limited partners and IDR holder utilizing the contractual terms of the partnership agreement. The distribution formula for available cash specified in the partnership agreement contractually mandates the way in which earnings are distributed.

Additionally, EITF 07-4 requires an MLP to reflect its contractual obligation to make distributions as of the end of the current reporting period. Therefore, an MLP would reduce (increase) income (loss) from continuing operations (or net income or loss) for the current reporting period by the amount of available cash that has been or will be distributed to the general partner, limited partners, and IDR holder for that current reporting period. If distributions to the IDR holder are contractually limited to available cash as defined in the partnership agreement, then the specified threshold for the current reporting period would be the holder's share of available cash that has been or will be distributed to the IDR holder for that current reporting period.

EITF 07-4 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Earlier application is not permitted. Our adoption of EITF 07-4 is not expected to impact our consolidated financial position, results of operations, cash flows or our computation of earnings per common and subordinated unit.

Note 4—Property, Plant and Equipment

Property, plant, and equipment and accumulated depreciation were as follows as of the dates indicated:

	December 31, 2008	December 31, 2007
	(In thousands)	
Natural Gas Gathering Systems	$ 1,161,942	$ 1,132,860
Processing and fractionation facilities	237,321	230,931
Other property, plant, and equipment	68,003	60,946
Construction in progress	25,460	9,218
	1,492,726	1,433,955
Accumulated depreciation	(248,389)	(174,361)
	$ 1,244,337	$ 1,259,594

Note 5—Asset Retirement Obligations

The changes in our aggregate asset retirement obligations are as follows:

	Year Ended December 31, 2008	2007	2006
		(In thousands)	
Beginning of year	$ 3,262	$ 2,888	$ 2,644
Liabilities settled	(229)	-	-
Change in cash flow estimate	258	32	(1)
Accretion expense	231	342	245
End of period	$ 3,522	$ 3,262	$ 2,888

Our asset retirement obligations are included in our Consolidated Balance Sheets as a component of other long-term liabilities.

Note 6—Debt Obligations

Our consolidated outstanding debt, including outstanding borrowings and issued letters of credit as of the dates shown below was:

	December 31, 2008	December 31, 2007
	(In thousands)	
Senior unsecured notes, 8¼% fixed rate, due July 1, 2016	$ 209,080	$ -
Senior secured credit facility, variable rate, due February 14, 2012	487,765	626,300
Total long-term debt	$ 696,845	$ 626,300
Letters of credit issued	$ 9,651	$ 25,900

On October 16, 2008, we requested a $100 million funding under our credit facility. Lehman Bank, a lender under our credit facility, defaulted on its portion of the borrowing request resulting in an actual funding of $97.8 million. As a result of the default, we believe the availability under the credit facility has been effectively reduced by approximately $10.0 million.

Repurchases of Senior Notes

During November and December 2008, we repurchased $40.9 million face amount of our outstanding Senior Notes in open market transactions at an aggregate purchase price of $28.3 million including $1.5 million of accrued interest. We recognized a gain of $13.1 million from these transactions. The repurchased Notes were retired and are not eligible for re-issue at a later date.

Information Regarding Variable Interest Rates Paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable-rate debt obligations during 2008:

	Range of interest rates paid	**Weighted average interest rate paid**
Credit facility	1.5% to 6.4%	4.4%

Pre-IPO Indebtedness

On January 1, 2007, Targa contributed to us affiliated indebtedness related to the North Texas System of approximately $904.5 million (including accrued interest of $88.3 million computed at 10% per annum). We recorded approximately $9.8 million in interest expense associated with this affiliated debt for the period from January 1, 2007 through February 13, 2007. On February 14, 2007, Targa contributed its interest in Targa North Texas GP LLC and Targa North Texas LP to us.

The stated 10% interest rate in the formal debt arrangement was not indicative of prevailing external rates of interest including that incurred under our credit facility which is secured by substantially all of our assets. On a pro forma basis, at prevailing interest rates the affiliated interest expense for the period from January 1, 2007 to February 13, 2007 would have been reduced by $3.0 million. The pro forma interest expense adjustment has been calculated by applying the weighted average rate of 6.9% that we incurred under our credit facility to the affiliate debt balance for the period from January 1, 2007 to February 13, 2007.

Credit Agreement

On February 14, 2007, we entered into a credit agreement which provided for a five-year $500 million credit facility with a syndicate of financial institutions. The credit facility bears interest at our option, at the higher of the lender’s prime rate or the federal funds rate plus 0.5%, plus an applicable margin ranging from 0% to 1.25% dependent on our total leverage ratio, or LIBOR plus an applicable margin ranging from 1.0% to 2.25% dependent on our total leverage ratio. We initially borrowed $342.5 million under our credit facility, and concurrently repaid $48.0 million under our credit facility with the proceeds from the 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units. The net proceeds of $294.5 million from this borrowing, together with approximately $371.2 million of available cash from the IPO (after payment of offering and debt issue costs and necessary operating cash reserve balances), were used to repay approximately $665.7 million of affiliate indebtedness. In connection with our IPO, the guarantee of indebtedness from the entity holding the North Texas System was terminated, the related collateral interest was released and the remaining affiliate indebtedness was retired and treated as a capital contribution to us. Our credit facility is secured by substantially all of our assets.

On October 24, 2007, we completed the acquisition of the SAOU and LOU Systems from Targa. As part of the acquisition of the SAOU and LOU Systems, the allocated indebtedness was settled with Targa through an adjustment to parent equity and the collateralization of the assets was released.

Concurrent with the acquisition of the SAOU and LOU Systems, we entered into a Commitment Increase Supplement (the “Supplement”) to our existing credit facility. The Supplement increased the aggregate commitments under the Credit Agreement by $250 million to an aggregate $750 million. We paid for our acquisition of the SAOU and LOU Systems with the proceeds from our offering of common units and approximately $378.9 million in incremental borrowings under the increased credit facility. Substantially all of our assets (North Texas, SAOU and LOU Systems) are currently pledged as collateral on our credit facility.

On October 24, 2007, we entered into the First Amendment to Credit Agreement (the “Amendment”). The Amendment increased by $250 million the maximum amount of increases to the aggregate commitments that may be requested by us. The Amendment allows us to request commitments under the credit agreement, as supplemented and amended, up to $1 billion.

On June 18, 2008, we increased the commitments under our credit facility by $100 million, bringing the total commitments under our credit facility to $850 million. We may request additional commitments under our credit facility of up to $150 million, which would increase the total commitments under our credit facility to $1 billion.

The credit agreement restricts our ability to make distributions of available cash to unitholders if we are in any default or an event of default (as defined in the credit agreement) exists. The credit agreement requires us to maintain a leverage ratio (the ratio of consolidated indebtedness to our consolidated EBITDA, as defined in the credit agreement) of no more than 5.50 to 1.00 on the last day of any fiscal quarter. The credit agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, as defined in the credit agreement) of no less than 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination. In addition, the credit agreement contains various covenants that may limit, among other things, our ability to:

· incur indebtedness;

· grant liens; and

· engage in transactions with affiliates.

The credit facility matures on February 14, 2012, at which time all unpaid principal and interest is due.

8¼% Senior Notes due 2016

On June 18, 2008, we completed the private placement under Rule 144A and Regulation S of the Securities Act of 1933 (“Rule 144A”) of $250 million in aggregate principal amount of 8¼% senior notes due 2016 (the “Notes”). Proceeds from the Notes were used to repay borrowings under our credit facility.

The Notes:

· are our unsecured senior obligations;

· rank *pari passu* in right of payment with our existing and future senior indebtedness, including indebtedness under our credit facility;

· are senior in right of payment to any of our future subordinated indebtedness; and

· are unconditionally guaranteed by us.

The Notes are effectively subordinated to all secured indebtedness under our credit agreement, which is secured by substantially all of our assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the Notes accrues at the rate of 8¼% per annum and is payable semi-annually in arrears on January 1 and July 1, commencing on January 1, 2009. Interest is computed on the basis of a 360-day year comprising twelve 30-day months.

At any time prior to July 1, 2011, we may on any one or more occasions redeem up to 35% of the aggregate principal amount of the Notes with the net cash proceeds of one or more equity offerings by us; at a redemption price of 108.25% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date provided that:

(1) at least 65% of the aggregate principal amount of the Notes (excluding Notes held by us) remains outstanding immediately after the occurrence of such redemption; and

(2) the redemption occurs within 90 days of the date of the closing of such equity offering.

At any time prior to July 1, 2012, we may also redeem all or a part of the Notes at a redemption price equal to 100% of the principal amount of the Notes redeemed plus the applicable premium as defined in the indenture agreement as of, and accrued and unpaid interest and liquidated damages, if any, to the date of redemption.

On or after July 1, 2012, we may redeem all or a part of the Notes at the redemption prices set forth below (expressed as percentages of principal amount) plus accrued and unpaid interest and liquidated damages, if any, on the Notes redeemed, if redeemed during the twelve-month period beginning on July 1 of each year indicated below:

Year	Percentage
2012	104.125%
2013	102.063%
2014 and thereafter	100.000%

The Notes are subject to a registration rights agreement dated as of June 18, 2008. Under the registration rights agreement, we are required to file by June 19, 2009 a registration statement with respect to any Notes that are not freely transferable without volume restrictions by holders of the Notes that are not our affiliates. If we fail to do so, additional interest will accrue on the principal amount of the Notes. We have determined that the payment of additional interest is not probable. As a result, we have not recorded a liability for any contingent obligation. Any subsequent accrual of a liability under this registration rights agreement will be charged to earnings as interest expense.

Note 7—Partnership Equity and Distributions

General. The partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our Available Cash (defined below) to unitholders of record on the applicable record date, as determined by the general partner.

Definition of Available Cash. Available Cash, for any quarter, consists of all cash and cash equivalents on hand on the date of determination of available cash for that quarter: less the amount of cash reserves established by the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to the unitholders and to the general partner for any one or more of the next four quarters.

General Partner Interest and Incentive Distribution Rights. The general partner is currently entitled to approximately 2% of all quarterly distributions that we make prior to our liquidation. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions will be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner's incentive distribution rights are not reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Please read "Distributions of Available Cash during the Subordination Period" and "Distributions of Available Cash after the Subordination Period" below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Subordinated Units. All of the subordinated units are indirectly held by Targa. Our partnership agreement provides that, during the subordination period, the common units have the right to receive distributions of Available Cash each quarter in an amount equal to $0.3375 per common unit, or the "Minimum Quarterly Distribution," plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The earliest date at which the subordination period may end is May 19, 2009.

Distributions of Available Cash during the Subordination Period. Based on the general partner's initial 2% ownership percentage, the partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter during the subordination period in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;
- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.3881 per unit for that quarter (the First Target Distribution);
- *fifth*, 85% to all unitholders, 2% to the general partner and 13% to the holders of the Incentive Distribution Rights, pro rata, until each unitholder receives a total of $0.4219 per unit for that quarter (the Second Target Distribution);
- *sixth*, 75% to all unitholders, 2% to the general partner and 23% to the holders of the Incentive Distribution Rights, pro rata, until each unitholder receives a total of $0.50625 per unit for that quarter (the Third Target Distribution); and
- *thereafter*, 50% to all unitholders, 2% to the general partner and 48% to the holders of the Incentive Distribution Rights, pro rata, (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period. The partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.3881 per unit for that quarter;
- *second*, 85% to all unitholders, pro rata, 2% to the general partner and 13% to the holders of the Incentive Distribution Rights, until each unitholder receives a total of $0.4219 per unit for that quarter;
- *third*, 75% to all unitholders, pro rata, 2% to the general partner and 23% to the holders of the Incentive Distribution Rights, until each unitholder receives a total of $0.50625 per unit for that quarter; and
- *thereafter*, 50% to all unitholders, pro rata, 2% to the general partner and 48% to the holders of the Incentive Distribution Rights.

The following table shows the amount of the cash distributions we paid for the period from February 14, 2007 through December 31, 2008.

		Distributions Paid					Distributions
		Common	Subordinated	General Partner			per limited
Date Declared	Date Paid	Units	Units	Incentive	2%	Total	partner unit
		(In thousands, except per unit amounts)					
October 23, 2008	November 14, 2008	$ 17,934	$ 5,966	$ 1,931	$ 527	$ 26,358	$ 0.51750
July 23, 2008	August 14, 2008	17,759	5,908	1,711	518	25,896	0.51250
April 23, 2008	May 15, 2008	14,467	4,813	208	398	19,886	0.41750
January 23, 2008	February 14, 2008	13,768	4,582	66	376	18,792	0.39750
July 24, 2007	November 14, 2007	11,082	3,891	-	305	15,278	0.33750
July 24, 2007	August 14, 2007	6,526	3,890	-	212	10,628	0.33750
April 23, 2007	May 15, 2007	3,263	1,945	-	107	5,315	0.16875

On January 23, 2009, we declared a cash distribution of $0.5175 per unit on our outstanding common and subordinated units. The distribution was paid on February 13, 2009 to unitholders of record on February 4, 2008, for the period October 1, 2008 through December 31, 2008. The total distribution paid was approximately $26.4 million, with approximately $23.9 million paid to our common unitholders and $0.5 million and $1.9 million paid to our general partner for its general partner and incentive distribution interests.

Note 8—Accounting for Unit-Based Compensation

Our general partner has adopted a long-term incentive plan ("the Plan") for employees, consultants and directors of the general partner and its affiliates who perform services for us. The following table summarizes our unit-based awards for each of the periods indicated:

	Year Ended December 31,		
	2008	2007	2006
Outstanding at beginning of period	16,000	-	-
Granted	16,000	16,000	-
Vested	(5,336)	-	-
Forfeited	-	-	-
Outstanding at end of period	26,664	16,000	-
Weighted average grant date fair value per share	$ 22.12	$ 21.00	$ -

During 2008 and 2007, our general partner awarded 2,000 restricted common units in the Partnership to each of the general partner's and Targa Investments' non-management directors under the Plan. The awards will settle with the delivery of common units and are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant date.

Compensation expense on the restricted common units is recognized on a straight-line basis over the vesting period. The fair value of an award of restricted common units is measured on the grant date using the market price of a common unit on such date. During 2008 and 2007, we recognized compensation expense of $0.3 million and $0.2 million related to these awards. We estimate that the remaining fair value of $0.2 million will be recognized in expense over approximately one year.

Note 9 — Derivative Instruments and Hedging Activities

As of December 31, 2008, OCI included $89.6 million of unrealized net gains on commodity hedges. As of December 31, 2007, OCI included $74.0 million of unrealized net losses on commodity hedges.

For 2008, 2007 and 2006 deferred net losses on commodity hedges of $33.7 million, $1.0 million and $0.9 million were reclassified from OCI to revenues. There were no adjustments for hedge ineffectiveness for 2008, 2007 or 2006.

As of December 31, 2008 and 2007, OCI also included $17.6 million and $1.2 million of unrealized losses on interest rate hedges.

For 2008, 2007 and 2006, deferred net gain (losses) on interest rate hedges of $2.7 million, ($0.2) million and ($0.5) million were reclassified from OCI to net interest expense. There were no adjustments for hedge ineffectiveness for 2008, 2007 or 2006.

As of December 31, 2008, deferred net gains (losses) of $50.0 million on commodity hedges and ($8.0) million on interest rate hedges recorded in OCI are expected to be reclassified to expense during the next twelve months.

In May 2008 we entered into certain NGL derivative contracts with Lehman Brothers Commodity Services Inc., a subsidiary of Lehman Brothers Holdings Inc. (“Lehman”). Due to Lehman’s bankruptcy filing, it is unlikely that we will receive full or partial payment of any amounts that may become owed to us under these contracts. Accordingly, we discontinued hedge accounting treatment for these contracts as of July 1, 2008. Deferred losses of $0.1 million and $0.3 million will be reclassified from OCI to revenues during 2011 and 2012 when the forecasted transactions related to these contracts are expected to occur. During 2008, we recognized a non-cash mark-to-market loss on derivatives of $1.0 million to adjust the fair value of the Lehman derivative contracts to zero. On October 22, 2008, we terminated the Lehman derivative contracts.

During July 2008, we paid $87.4 million to terminate certain out-of-the-money natural gas and NGL commodity swaps. Prior to the terminations, these swaps were designated as hedges in accordance with SFAS 133. Deferred losses will be reclassified from OCI as a non-cash reduction of revenue when the hedged forecasted sales transactions occurs. During 2008, deferred losses of $20.8 million were reclassified from OCI as a non-cash reduction to revenue. We also entered into new natural gas and NGL commodity swaps at then current market prices that match the production volumes of the terminated swaps through 2010.

As of December 31, 2008, our commodity hedges that have been designated as cash flow hedges were as follows:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per day 2009	2010	2011	2012	Fair Value (In thousands)
Natural Gas Sales							
Swap	IF-HSC	7.39	1,966	-	-	-	$ 1,159
			1,966	-	-	-	
Swap	IF-NGPL MC	9.18	6,256	-	-	-	9,466
Swap	IF-NGPL MC	8.86	-	5,685	-	-	5,129
Swap	IF-NGPL MC	7.34	-	-	2,750	-	843
Swap	IF-NGPL MC	7.18	-	-	-	2,750	738
			6,256	5,685	2,750	2,750	
Swap	IF-Waha	8.73	6,936	-	-	-	8,627
Swap	IF-Waha	7.52	-	5,709	-	-	2,294
Swap	IF-Waha	7.36	-	-	3,250	-	886
Swap	IF-Waha	7.18	-	-	-	3,250	708
			6,936	5,709	3,250	3,250	
Total Swaps			15,158	11,394	6,000	6,000	
Floor	IF-NGPL MC	6.55	850	-	-	-	574
			850	-	-	-	
Floor	IF-Waha	6.55	565	-	-	-	326
			565	-	-	-	
Total Floors			1,415	-	-	-	
Total Sales			16,573	11,394	6,000	6,000	
							$ 30,750

NGL

Instrument Type	Index	Avg. Price $/gal	Barrels per day 2009	2010	2011	2012	Fair Value (In thousands)
NGL Sales							
Swap	OPIS-MB	1.32	6,248	-	-	-	$ 66,137
Swap	OPIS-MB	1.27	-	4,809	-	-	39,122
Swap	OPIS-MB	0.92	-	-	3,400	-	8,288
Swap	OPIS-MB	0.92	-	-	-	2,700	6,018
Total Swaps			6,248	4,809	3,400	2,700	
Floor	OPIS-MB	1.44	-	-	199	-	1,807
Floor	OPIS-MB	1.43	-	-	-	231	1,932
Total Floors			-	-	199	231	
Total Sales			6,248	4,809	3,599	2,931	
							$ 123,304

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per day 2009	2010	2011	2012	Fair Value (In thousands)
Condensate Sales							
Swap	NY-WTI	69.00	322	-	-	-	$ 1,655
Swap	NY-WTI	68.10	-	301	-	-	431
Total Swaps			322	301	-	-	
Floor	NY-WTI	60.00	50	-	-	-	239
Total Floors			50	-	-	-	
Total Sales			372	301	-	-	
							$ 2,325

As of December 31, 2008, we had the following commodity derivative contracts directly related to fixed price arrangements elected by certain customers in various natural gas purchase and sale agreements, which have been marked to market through earnings:

Period	Commodity	Instrument Type	Daily Volume		Average Price		Index	Fair Value (In thousands)
Purchases								
Jan 2009 - Dec 2009	Natural gas	Swap	6,005	MMBtu	7.50	per MMBtu	NY-HH	$ (3,644)
Jan 2010 - Jun 2010	Natural gas	Swap	1,304	MMBtu	8.03	per MMBtu	NY-HH	(113)
Sales								
Jan 2009 - Dec 2009	Natural gas	Fixed price sale	6,005	MMBtu	7.50	per MMBtu	NY-HH	3,610
Jan 2010 - Jun 2010	Natural gas	Fixed price sale	1,304	MMBtu	8.03	per MMBtu	NY-HH	113
								$ (34)

The fair value of derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. These contracts may expose us to the risk of financial loss in certain circumstances.

Our earnings are also affected by use of the mark-to-market method of accounting for derivative financial instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the “mark-to-market” method) rather than being deferred until the anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. During 2008, 2007 and 2006, we recorded mark-to-market gains (losses) of ($1.0) million, ($30.2) million and $16.8 million.

Interest Rate Swaps

As of December 31, 2008, we had $487.8 million outstanding under our credit facility, with interest accruing at a base rate plus an applicable margin. In order to mitigate the risk of changes in cash flows attributable to changes in market interest rates we have entered into interest rate swaps and interest rate basis swaps that effectively fix the base rate on $300 million in borrowings as shown below:

Expiration Date	Fixed Rate	Notional Amount Amount	Fair Value (In thousands)
January 24, 2011	4.00%	$100 million	$ (5,282)
January 24, 2012	3.75%	200 million	(12,294)
			$ (17,576)

All interest rate swaps and interest rate basis swaps have been designated as cash flow hedges of variable rate interest payments on $50 million in borrowings under our credit facility.

The following schedules reflect the fair values of derivative instruments in our Consolidated Balance Sheets and the effect of derivative instruments on our Consolidated Statements of Operations.

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Fair Value as of December 31, 2008	2007	Balance Sheet Location	Fair Value as of December 31, 2008	2007
		(In thousands)			(In thousands)	
Derivatives designated as hedging instruments under Statement 133						
Commodity contracts	Current assets	$ 88,206	$ 8,410	Current liabilities	$ -	$ 43,461
	Other assets	68,296	3,040	Other liabilities	123	42,134
Interest rate contracts	Current assets	-	-	Current liabilities	8,020	257
	Other assets	-	-	Other liabilities	9,556	975
Total		156,502	11,450		17,699	86,827
Derivatives not designated as hedging instruments under Statement 133						
Commodity contracts	Current assets	3,610	285	Current liabilities	3,644	285
	Other assets	-	-	Other liabilities	-	-
Total		3,610	285		3,644	285
Total derivatives		$ 160,112	$ 11,735		$ 21,343	$ 87,112

Derivatives in Statement 133 Cash Flow Hedging Relationships	**Amount of Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) Year Ended December 31, 2008**	**2007**	**2006**	**Location of Gain (Loss) Reclassified from OCI into Income (Effective Portion)**	**Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Year Ended December 31, 2008**	**2007**	**2006**
		(In thousands)				**(In thousands)**	
Interest rate contracts	$ (19,037)	$ (1,689)	$ 1,267	Interest expense, net	$ (2,693)	$ 232	$ -
Commodity contracts	130,002	(105,584)	36,937	Revenues	(33,650)	(993)	822
	$ 110,965	$ (107,273)	$ 38,204		$ (36,343)	$ (761)	$ 822

Derivatives Not Designated as Hedging Instruments Under Statement 133	**Location of Gain (Loss) Recognized in Income on Derivatives**	**Amount of Gain (Loss) Recognized in Income on Derivatives Year Ended December 31, 2008**	**2007**	**2006**
			(In thousands)	
Commodity contracts	Other income (expense)	$ (991)	$ (30,221)	$ 16,756

See also Note 3 and Note 12 for additional disclosures related to derivative instruments and hedging activities.

Note 10—Related-Party Transactions

Targa Resources, Inc.

On February 14, 2007, we entered into an Omnibus Agreement with Targa, our general partner and others that addressed the reimbursement of our general partner for costs incurred on our behalf and indemnification matters. Any or all of the provisions of this agreement, other than the indemnification provisions described in Note 11, are terminable by Targa at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal.

Concurrently with the closing of the acquisition of the SAOU and LOU Systems, we amended and restated our Omnibus Agreement (as amended and restated) with Targa, our general partner and others that addresses the reimbursement of our general partner for costs incurred on our behalf, competition and indemnification matters. Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions described in Note 11, are terminable by Targa at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The Omnibus Agreement will terminate in the event of a change of control of us or our general partner.

Reimbursement of Operating and General and Administrative Expense

Under the Omnibus Agreement, we reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel, and for the provision of various general and administrative services for our benefit. With respect to the North Texas System, we reimburse Targa for the following expenses:

- general and administrative expenses, which are capped at $5 million annually for three years, subject to increases based on increases in the Consumer Price Index and subject to further increases in connection with expansions of our operations through the acquisition or construction of new assets or businesses with the concurrence of our conflicts committee; thereafter, our general partner will determine the general and administrative expenses to be allocated to us in accordance with our partnership agreement, and

- operations and certain direct general and administrative expenses, which are not subject to the $5 million cap for general and administrative expenses.

With respect to the SAOU and LOU Systems, we will reimburse Targa for the following expenses:

- general and administrative expenses, which are not capped, allocated to the SAOU and LOU Systems according to Targa's allocation practice; and

- operating and certain direct expenses, which are not capped.

Pursuant to these arrangements, Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We reimburse Targa for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits.

Contracts with Affiliates

Sales to and purchases from affiliates. We routinely conduct business with other subsidiaries of Targa. The related party transactions result primarily from purchases and sales of natural gas and NGLs. Prior to February 14, 2007, all of our expenditures were paid through Targa, resulting in intercompany transactions. Prior to February 14, 2007, settlement of these inter-company transactions was through adjustments to partners' capital accounts. Effective February 14, 2007, all of the North Texas Systems transactions were settled monthly in cash. Effective October 23, 2007, all of the SAOU and LOU Systems' transactions were settled in cash.

NGL and Condensate Purchase Agreement for the North Texas System. During 2007, we entered into an NGL and high pressure condensate purchase agreement with Targa Liquids Marketing and Trade ("TLMT") for our North Texas System, which has an initial term of 15 years and will automatically extend for a term of five years, unless the agreement is otherwise terminated by either party, pursuant to which (i) we are obligated to sell all volumes of NGLs (other than high-pressure condensate) that we own or control to TLMT and (ii) we have the right to sell to TLMT or third parties the volumes of high-pressure condensate that we own or control, in each case at a price based on the prevailing market price less transportation, fractionation and certain other fees. Furthermore, either party may elect to terminate the agreement if either party ceases to be an affiliate of Targa.

NGL Purchase Agreements for the SAOU and LOU Systems. During 2007, the SAOU System entered into an NGL purchase agreement pursuant to which it is obligated to sell all volumes of mixed NGLs, or raw product, that it owns or controls to TLMT at a price based on either TLMT's sales price to third parties or the prevailing market price, less transportation, fractionation and certain other fees. The LOU System also has entered into an NGL purchase agreement pursuant to which (i) it has the right to sell to TLMT the volumes of raw product that it owns or controls at a commercially reasonable price agreed by the parties, and (ii) it is obligated to sell all volumes of fractionated NGL components that it owns or controls at a price based on TLMT's sales price to third parties or the prevailing market price, less transportation, fractionation and certain other fees. Both NGL purchase agreements have an initial term of one year and automatically extend for additional terms of one year, unless the agreements are otherwise terminated by either party.

Natural Gas Purchase Agreements. During 2007, the North Texas, SAOU and LOU Systems entered into natural gas purchase agreements at a price based on Targa Gas Marketing LLC's ("TGM") sale price for such natural gas, less TGM's costs and expenses associated therewith. These agreements have an initial term of 15 years and automatically extend for a term of five years, unless the agreements are otherwise terminated by either party. Furthermore, either party may elect to terminate the agreements if either party ceases to be an affiliate of Targa. In addition, Targa manages the SAOU and LOU Systems' natural gas sales to third parties under contracts that remain in the name of the Targa Texas Field Services and Targa Louisiana Field Services.

Allocations

Allocation of costs. The employees supporting our operations are employees of Targa. Our financial statements include costs allocated to us by Targa for centralized general and administrative services performed by Targa, as well as depreciation of assets utilized by Targa's centralized general and administrative functions. Costs allocated to us were based on identification of Targa's resources which directly benefit us and our proportionate share of costs based on our estimated usage of shared resources and functions. All of the allocations are based on assumptions that management believes are reasonable; however, these allocations are not necessarily indicative of the costs and expenses that would have resulted if we had been operated as a stand-alone entity. Prior to the initial IPO and the subsequent acquisition of the SAOU and LOU Systems these allocations were not settled in cash, but were settled through an adjustment to partners' capital accounts. Effective February 14, 2007, all of the North Texas Systems allocations were settled monthly in cash. Effective October 23, 2007, all of the SAOU and LOU Systems allocations were settled monthly in cash.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. Prior to January 1, 2007, our financial statements included long-term debt, debt issue costs, interest rate swaps and interest expense allocated from Targa. The allocations were calculated in a manner similar to Targa's purchase price allocation related to its acquisition of the SAOU and LOU Systems and were based on the fair value of acquired tangible assets plus related net working capital and unconsolidated equity interests. These allocations were not settled in cash. Settlement of these allocations occurred through adjustments to partners' capital. The allocated debt, debt issue costs and interest rate swaps for the North Texas System, were settled through a deemed partner contribution of $846.3 million on January 1, 2007. The allocated debt, debt issue costs and interest rate swaps related to the SAOU and LOU Systems were settled through a deemed partner contribution of $179.6 million.

The following table summarizes the sales to and purchases from affiliates of Targa, payments made or received by Targa on behalf of us and allocations of costs from Targa which were settled through adjustments to partners' capital prior to the contribution of the North Texas System by Targa and the acquisition of the SAOU/LOU Systems from Targa. Management believes these transactions are executed on terms that are fair and reasonable.

	Year Ended December 31,		
	2008	2007	2006
	(In thousands)		
Sales to affiliates	$ 1,225,393	$1,030,696	$ 786,589
Purchases from affiliates	323,970	191,064	322,917
Allocations of general & administrative expenses - pre IPO	-	9,720	16,062
Allocations of general & administrative expenses under Omnibus Agreement	18,204	5,927	-
Allocated interest	-	19,436	88,025
Receipts made by Parent on our behalf	-	584,561	268,043
Net change in affliate receivable	(65,252)	87,547	-

Centralized Cash Management

Prior to the contribution of the assets of the North Texas, SAOU and LOU Systems to us, the excess cash from these subsidiaries was held in separate bank accounts and swept to a centralized account under Targa. Beginning with the contribution of these systems to us, their bank accounts have been maintained under a separate centralized cash management system.

For the North Texas System, prior to February 14, 2007, cash distributions are deemed to have occurred through partners' capital and are reflected as an adjustment to partners' capital. For the period from January 1, 2007 through February 13, 2007, deemed net capital distributions from us were $0.5 million.

For the SAOU and LOU Systems for the period from January 1, 2007 though October 23, 2007, deemed net capital distributions from us were $133.6 million.

Relationships with Warburg Pincus

Chansoo Joung and Peter Kagan, two of the directors of Targa, are Managing Directors of Warburg Pincus and are also directors of Broad Oak Energy, Inc. ("Broad Oak") from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus own a controlling interest in Broad Oak. We purchased $4.8 million of product from Broad Oak during 2008. We had no commercial transactions prior to 2008 with Broad Oak. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Relationships with Noble Energy

Chris Tong, one of the directors of Targa, is a Senior Vice President and Chief Financial Officer of Noble Energy, Inc. ("Noble") from whom we buy certain commodity products. We had net purchases of less than $0.1 million, $0.1 million and $1.7 million of natural gas and NGL products from Noble during 2008, 2007 and 2006. These transactions were at market prices consistent with similar transactions with nonaffiliated entities.

Other

Commodity hedges. An affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated ("Merrill Lynch") holds an equity interest in Targa Investments, which indirectly owns our general partner. We have entered into various commodity derivative transactions with Merrill Lynch Commodities Inc. ("MLCI") an affiliate of Merrill Lynch. The following table shows our open commodity derivatives with MLCI as of December 31, 2008:

Period	Commodity	Instrument Type	Daily Volumes		Average Price		Index
Jan 2009 - Dec 2009	Natural gas	Swap	3,556	MMBtu	$ 8.07	per MMBtu	IF-Waha
Jan 2009 - Dec 2009	Natural gas	Swap	575	MMBtu	7.83	per MMBtu	NY-HH
Jan 2010 - Dec 2010	Natural gas	Swap	3,289	MMBtu	7.39	per MMBtu	IF-Waha
Jan 2010 - Dec 2010	Natural gas	Swap	247	MMBtu	8.17	per MMBtu	NY-HH
Jan 2009 - Dec 2009	NGL	Swap	3,000	Bbl	1.18	per gallon	OPIS-MB
Jan 2009 - Dec 2009	Condensate	Swap	202	Bbl	70.60	per barrel	NY-WTI
Jan 2010 - Dec 2010	Condensate	Swap	181	Bbl	69.28	per barrel	NY-WTI

As of December 31, 2008, the fair value of these open positions is $32.0 million. During 2008, 2007 and 2006, we paid to (received from) MLCI $9.1 million, $1.9 million and $(4.2) million in commodity derivative settlements.

Note 11—Commitments and Contingencies

Future non-cancelable commitments related to certain contractual obligations are presented below.

	Payments Due by Period						
	Total	2009	2010	2011	2012	2013	Thereafter
				(In thousands)			
Capacity payments	$ 8,215	$ 5,419	$ 2,050	$ 746	$ -	$ -	$ -
Right-of-way	4,889	348	331	330	319	233	3,328
	$ 13,104	$ 5,767	$ 2,381	$ 1,076	$ 319	$ 233	$ 3,328

Total expenses related to operating lease obligations, capacity payments and right-of-way payments were $5.9 million, $5.7 million and $3.2 million for 2008, 2007 and 2006.

Environmental

Under the Omnibus Agreement described in Note 10, Targa has indemnified us for three years from February 14, 2007 against certain potential environmental claims, losses and expenses associated with the operation of the North Texas System occurring before such date that were not reserved on the books of the North Texas System. Targa's maximum liability for this indemnification obligation will not exceed $10.0 million and Targa will not have any obligation under this indemnification until our aggregate losses exceed $250,000. We have indemnified Targa against environmental liabilities related to the North Texas System arising or occurring after February 14, 2007.

Our environmental liabilities not covered by the Omnibus Agreement are for ground water assessment and remediation and was less than $0.1 million as of December 31, 2008.

Litigation

On December 8, 2005, WTG Gas Processing ("WTG") filed suit in the 333rd District Court of Harris County, Texas against several defendants, including Targa Resources, Inc. and three other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips Company ("ConocoPhillips") and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase the SAOU System from ConocoPhillips and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from Targa's competition to purchase the ConocoPhillips' assets and its successful acquisition of those assets in 2004. On October 2, 2007, the District Court granted defendants' motions for summary judgment on all of WTG's claims. WTG's motion to reconsider and for a new trial was overruled. On January 2, 2008, WTG filed a notice of appeal. On February 3, 2009, the parties presented oral arguments and the appeal is pending before the 14^{th} Court of Appeals in Houston, TX. We are contesting WTG's appeal, but can give no assurances regarding the outcome of the proceeding. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit.

We are not a party to any other legal proceedings other than legal proceedings arising in the ordinary course of our business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business.

Note 12—Fair Value of Financial Instruments

The estimated fair values of our assets and liabilities classified as financial instruments have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. Derivative financial instruments included in our financial statements are stated at fair value. The carrying amounts and fair values of our other financial instruments are as follows as of the dates indicated.

The carrying value of the credit facility approximates its fair value, as its interest rate is based on prevailing market rates. The fair value of the senior notes is based on quoted market prices based on trades of such debt.

	As of December 31,			
	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Credit facility	$ 487,765	$ 487,765	$ 626,300	$ 626,300
Senior unsecured notes	209,080	128,333	-	-

Note 13—Fair Value Measurements

SFAS 157 established a three-tier fair value hierarchy, which prioritized 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.

Our derivative instruments consist of financially settled commodity and interest rate swap and option contracts and fixed price commodity contracts with certain customers. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are either readily available in public markets or are quoted by counterparties to these contracts. In situations where we obtain inputs via quotes from our counterparties, we verify the reasonableness of these quotes via similar quotes from another source for each date for which financial statements are presented. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold. We have categorized the inputs for these contracts as Level 2 or Level 3. The price quotes for the Level 3 inputs are provided by a counterparty with whom we regularly transact business.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2008. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Total	Level 1	Level 2	Level 3
		(In thousands)		
Assets from commodity derivative contracts	$ 160,112	$ -	$ 36,808	$ 123,304
Assets from interest rate derivatives	-	-	-	-
Total assets	$ 160,112	$ -	$ 36,808	$ 123,304
Liabilities from commodity derivative contracts	$ 3,767	$ -	$ 3,767	$ -
Liabilities from interest rate derivatives	17,576	-	17,576	-
Total liabilities	$ 21,343	$ -	$ 21,343	$ -

The following table sets forth a reconciliation of the changes in the fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts
	(In thousands)
Balance, December 31, 2007	$ (71,370)
Total gains (losses) realized/unrealized	
Included in loss on mark-to-market derivatives	(991)
Included in OCI	100,068
Purchases	2,866
Terminations	77,792
Settlements	14,939
Balance, December 31, 2008	$ 123,304

No unrealized gains or losses were reported relating to assets and liabilities still held as of December 31, 2008.

Note 14— Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate in the midstream energy industry. Our business activities include gathering, transporting and processing of natural gas, NGLs and crude oil. As such, our results of operations, cash flows and financial condition may be affected by (i) changes in the commodity prices of these hydrocarbon products and (ii) changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGLs, crude oil and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities. A material decrease in natural gas or crude oil production or crude oil refining, as a result of depressed commodity prices, a decrease in exploration and development activities or otherwise, could result in a decline in the volume of natural gas, NGLs and crude oil handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made with NGL products, (iii) increased competition from petroleum-based products due to the pricing differences, (iv) adverse weather conditions, (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could also adversely affect our results of operations, cash flows and financial position.

Counterparty Risk with Respect to Financial Instruments

Where we are exposed to credit risk in our financial instrument transactions, management analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit and/or margin limits and monitors the appropriateness of these limits on an ongoing basis. Generally, management does not require collateral and does not anticipate nonperformance by our counterparties.

Casualty or Other Risks

Targa maintains coverage in various insurance programs on our behalf, which provides us with property damage, business interruption and other coverages which are customary for the nature and scope of our operations.

Management believes that Targa has adequate insurance coverage, although insurance may not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies have increased substantially, and in some instances, certain insurance may become unavailable, or available for only reduced amounts of coverage. As a result, Targa may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts the revenues generated by us, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our financial obligations.

A portion of the insurance costs described above is allocated to us by Targa through the allocation methodology as prescribed in the Omnibus Agreement described in Note 11.

Under the Omnibus Agreement, Targa has also indemnified us for losses attributable to rights-of-way, certain consents or governmental permits, pre-closing litigation relating to the North Texas System and income taxes attributable to pre-closing operations that were not reserved on the books of the North Texas System as of February 14, 2007. Targa does not have any obligation under these indemnifications until our aggregate losses exceed $250,000. We have indemnified Targa for all losses attributable to the post-closing operations of the North Texas System. Targa's obligations under this additional indemnification will survive for three years from February 14, 2007, except that the indemnification for income tax liabilities will terminate upon the expiration of the applicable statutes of limitations.

Note 15— Selected Quarterly Financial Data (Unaudited)

Our results of operations by quarter for the years ended December 31, 2008 and 2007, as adjusted to reflect the consideration of common control accounting and change in predecessor entities as discussed in Note 1, were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
		(In thousands, except per unit amounts)			
Year Ended December 31, 2008:					
Revenues	$ 512,069	$ 630,520	$ 578,747	$ 352,782	$ 2,074,118
Operating income	33,974	36,525	26,815	21,720	119,034
Net income per common and subordinated unit	24,935	28,206	14,692	23,661	91,494
Net income per unit					
Basic	$ 0.50	$ 0.54	$ 0.31	$ 0.48	$ 1.83
Diluted	$ 0.50	$ 0.54	$ 0.31	$ 0.48	$ 1.83
Year Ended December 31, 2007:					
Revenues	$ 348,781	$ 433,615	$ 405,038	$ 474,035	$ 1,661,469
Operating income	20,739	28,183	29,965	34,467	113,354
Net income (loss) per common and subordinated unit	(10,627)	13,811	14,392	22,674	40,250
Net income per unit					
Basic	$ 0.07	$ 0.13	$ 0.12	$ 0.42	$ 0.81
Diluted	$ 0.07	$ 0.13	$ 0.12	$ 0.42	$ 0.81

Index to Exhibits

2.1**	Purchase and Sale Agreement, dated as of September 18, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 21, 2007 (File No. 001-33303)).
2.2	Amendment to Purchase and Sale Agreement, dated October 1, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
3.4	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.5	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.6	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Specimen Unit Certificate representing common units (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
4.2	Indenture dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 18, 2008 (File No. 001-33303)).
4.3	Registration Rights Agreement dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporations, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed June 18, 2008 (File No. 001-33303)).
10.1	Credit Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, as Borrower, Bank of America, N.A., as Administrative Agent, Wachovia Bank, N.A., as Syndication Agent, Merrill Lynch Capital, Royal Bank of Canada and The Royal Bank of Scotland PLC, as Co-Documentation Agents, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
10.2	Commitment Increase Supplement, dated October 24, 2007, by and among Targa Resources Partners LP, Bank of America, N.A. and the parties signatory thereto as the Increasing Lenders and the New Lenders (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
10.3	First Amendment to Credit Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Bank of America, N.A. and each Lender party thereto (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
10.4	Commitment Increase Supplement, dated June 18, 2008, by and among Targa Resources Partners LP, Bank of America, N.A. and other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 24, 2008 (File No. 001-33303)).
10.5	Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa North Texas GP LLC and Targa North Texas LP (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
10.6	Contribution, Conveyance and Assumption Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources Holdings LP, Targa TX LLC, Targa TX PS LP, Targa LA LLC, Targa LA PS LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
10.7	Amended and Restated Omnibus Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
10.8+	Targa Resources Partners Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).
10.9+	Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).

10.10+* Amendment to Targa Resources Partners LP Long-Term Incentive Plan dated December 18, 2008.

10.11+ Form of Restricted Unit Grant Agreement (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).

10.12+ Form of Performance Unit Grant Agreement (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 28, 2009 (File No. 001-33303)).

10.13+* Targa Resources Investments Inc. 2008 Annual Incentive Compensation Plan

10.14+* Targa Resources Investments Inc. 2009 Annual Incentive Compensation Plan

10.15 Gas Gathering and Purchase Agreement by and between Burlington Resources Oil & Gas Company LP, Burlington Resources Trading Inc. and Targa Midstream Services Limited Partnership (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 8, 2007 (File No. 333-138747)).

10.16 Natural Gas Purchase Agreement, effective January 1, 2007, by and between Targa Gas Marketing LLC (Buyer) and Targa North Texas LP (Seller) (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP's Registration Statement on Form S-1 filed October 1, 2007 (File No. 333-146436)).

10.17 NGL and Condensate Purchase Agreement, effective January 1, 2007, by and between Targa North Texas LP (Seller) and Targa Liquids Marketing and Trade (Buyer) (incorporated by reference to Exhibit 10.12 to Targa Resources Partners LP's Registration Statement on Form S-1 filed October 1, 2007 (File No. 333-146436)).

10.18 Product Purchase Agreement, effective January 1, 2007, by and between Targa Louisiana Field Services LLC (Seller) and Targa Liquids Marketing and Trade (Buyer) (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.19 Raw Product Purchase Agreement, effective January 1, 2007, by and between Targa Texas Field Services LP (Seller) and Targa Liquids Marketing and Trade (Buyer) (incorporated by reference to Exhibit 10.14 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.20 Amended and Restated Natural Gas Sales Agreement, effective December 1, 2005, by and between Targa Louisiana Field Services LLC (Buyer) and Targa Gas Marketing LLC (Seller) (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.21 Amended and Restated Natural Gas Purchase Agreement, effective December 1, 2005, by and between Targa Gas Marketing LLC (Buyer) and Targa Louisiana Field Services LLC (Seller) (incorporated by reference to Exhibit 10.16 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.22 Amended and Restated Natural Gas Purchase Agreement, effective December 1, 2005, by and between Targa Gas Marketing LLC (Buyer) and Targa Texas Field Services LP (Seller) (incorporated by reference to Exhibit 10.17 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed October 12, 2007 (File No. 333-146436)).

10.23+ Targa Resources Partners LP Indemnification Agreement for Barry R. Pearl dated February 14, 2007 (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).

10.24+ Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007 (incorporated by reference to Exhibit 10.12 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).

10.25+ Targa Resources Partners LP Indemnification Agreement for Williams D. Sullivan dated February 14, 2007 (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).

10.26 Purchase Agreement dated June 12, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 18, 2008 (File No. 001-33303)).

21.1* Subsidiaries of Targa Resources Partners LP

23.1* Consent of Independent Registered Public Accounting Firm

31.1* Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.

31.2* Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.

32.1* Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2* Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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* Filed herewith

** Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted exhibit or Schedule to the SEC upon request.

\+ Management contract or compensatory plan or arrangement.

TABLE OF CONTENTS

**AMENDMENT TO
TARGA RESOURCES INVESTMENTS INC.
KEY EMPLOYEE LONG TERM INCENTIVE PLAN**

WHEREAS, TARGA RESOURCES INVESTMENTS INC. (the "Company") has heretofore adopted the **TARGA RESOURCES INVESTMENTS INC. KEY EMPLOYEE LONG TERM INCENTIVE PLAN** (the "Plan") for the benefit of certain of the employees of the Company and its affiliates and as an incentive for such individuals to remain employees of the Company or its affiliates;

WHEREAS, the Company may amend the Plan at any time in its discretion; and

WHEREAS, the Company desires to amend the Plan to comply with section 409A of the Internal Revenue of Code of 1986, as amended;

NOW, THEREFORE, the Plan shall be amended as follows, effective as of December 18th, 2008:

1. Section 6 of the Plan shall be deleted, and the following shall be substituted therefore:

"6. Payment of Incentive Benefit After Death of Employee. If an Employee terminates employment due to death and is entitled to receive the Incentive Benefit which would be payable on the next following Employment Incentive Date pursuant to Section 4(a) hereof, such Incentive Benefit shall be paid in a lump sum cash payment, subject to applicable withholding, as soon as practicable after the date of death but in no event later than the 15th day of March following the end of the calendar year during which the death occurs to (a) the Employee's beneficiary (or beneficiaries) designated under the employer's group life insurance plan, if living, or, (b) if none is so designated or living, the executor of the Employee's estate."

2. The third sentence of Section 4(a) of the Plan shall be deleted, and the following shall be substituted therefore:

"Except as provided in Section 6 below with respect to payments made after the death of an Employee, such Incentive Benefit shall be payable in a lump sum cash payment, subject to applicable withholding, (A) within 20 business days after the date of termination in the event of a termination other than for Cause, or (B) in the event of a determination of Disability, no later than the earlier of (1) March 15 of the year following the year of the date of determination or (2) 30 business days after the Incentive Payment Date."

EXECUTED and effective as of December 18, 2008.

TARGA RESOURCES INVESTMENTS INC.

By:	**/s/** Rene R. Joyce
Name:	Rene R. Joyce
Title:	Chief Executive Officer

Exhibit 10.13

Targa Resources, Inc. 2008 Annual Incentive Plan Description

On January 17, 2008, the Compensation Committee (the “Committee”) of the Board of Directors (the “Board”) of Targa Resources Investments Inc. (“Targa Investments”), the indirect parent of Targa Resources, Inc. (the “Company”), approved the Targa Investments 2008 Annual Incentive Compensation Plan (the “Bonus Plan”). The Bonus Plan is a discretionary annual cash bonus plan available to all of the Company’s employees, including its executive officers. The purpose of the Bonus Plan is to reward employees for contributions toward the Company’s business priorities approved by the Committee and to aid the Company in retaining and motivating employees. Under the Bonus Plan, a discretionary cash bonus pool may be funded based on the Company’s achievement of certain business priorities recommended by the Company’s chief executive officer (the “CEO”) and approved by the Committee. The Bonus Plan is administered by the Committee, which considers certain recommendations by the CEO. Following the end of the year, the CEO recommends to the Committee the total amount of cash to be allocated to the bonus pool based upon the achievement of the business priorities of the Company, generally ranging from 0 to 2x the total target bonus for the employees in the pool. Upon receipt of the CEO’s recommendation, the Committee, in its sole discretion, determines the total amount of cash to be allocated to the bonus pool. Additionally, the Committee, in its sole discretion, determines the amount of the cash bonus award to each of the Company’s executive officers, including the CEO. The executive officers determine the amount of the cash bonus pool to be allocated to certain of the Company’s departments, groups and employees (other than the executive officers of the Company) based upon the recommendation of their supervisors, managers and line officers.

The Committee has established the following six key business priorities for 2008:

- Identify opportunities to strengthen organization and develop plans to address them
- Expand on existing processes to enhance the involvement of the organization in making our businesses better
- Aggressively develop attractive return projects and opportunities and proactively invest in and expand the Company’s businesses
- Improve insurance recovery situation with resolution or clear path to resolution
- Make a significant third-party acquisition(s) at Targa Resources Partners LP (our MLP) and/or continue to effectively drop down Company assets to our MLP
- Execute on all fronts (including the 2008 business plan and above priorities)

The Committee has targeted a total cash bonus pool for achievement of the business priorities based on the sum of individual employee market-based target percentages ranging from approximately 3% to 50% of each employee’s eligible earnings. Generally, eligible earnings are an employee’s base salary and overtime pay. The Committee has discretion to adjust the cash bonus pool attributable to the business priorities based on accomplishment of the applicable objectives as determined by the Committee and the CEO. Funding of the Company’s cash bonus pool and the payment of individual cash bonuses to employees are subject to the sole discretion of the Committee.

Targa Resources, Inc. 2009 Annual Incentive Plan Description

On January 22, 2009, the Compensation Committee (the "Committee") of the Board of Directors (the "Board") of Targa Resources Investments Inc. ("Targa Investments"), the indirect parent of Targa Resources, Inc. (the "Company"), approved the Targa Investments 2009 Annual Incentive Compensation Plan (the "Bonus Plan"). The Bonus Plan is a discretionary annual cash bonus plan available to all of the Company's employees, including its executive officers. The purpose of the Bonus Plan is to reward employees for contributions toward the Company's business priorities (including business priorities of Targa Resources Partners LP) approved by the Committee and to aid the Company in retaining and motivating employees. Under the Bonus Plan, funding of a discretionary cash bonus pool is expected to be recommended by the Company's chief executive officer (the "CEO") and approved by the Committee based on the Company's achievement of certain business priorities. The Bonus Plan is administered by the Committee, which considers certain recommendations by the CEO. Following the end of the year, the CEO recommends to the Committee the total amount of cash to be allocated to the bonus pool based upon the achievement of the business priorities of the Company, generally ranging from 0 to 2x the total target bonus for the employees in the pool. Upon receipt of the CEO's recommendation, the Committee, in its sole discretion, determines the total amount of cash to be allocated to the bonus pool. Additionally, the Committee, in its sole discretion, determines the amount of the cash bonus award to each of the Company's executive officers, including the CEO. The executive officers determine the amount of the cash bonus pool to be allocated to certain of the Company's departments, groups and employees (other than the executive officers of the Company) based on performance and upon the recommendation of their supervisors, managers and line officers.

The Committee has established the following eight key business priorities for 2009:

- manage controllable costs to levels at or below plan levels – with a continuous effort to improve costs for 2009 and beyond;
- examine, prioritize, and approve each capital project closely for economics (or necessity) in the current environment;
- increase scrutiny and proactively manage credit and liquidity across finance, credit and commercial areas;
- reduce (eliminate where appropriate) downstream's inventory exposure (for the Company only);
- continue to invest in our businesses primarily within existing cash flow;
- pursue selected opportunities including new shale play gathering and processing build outs, other fee-based capex projects and the potential to purchase distressed strategic assets;
- analyze and recommend approaches to achieve maximum value; and
- execute on the above priorities, including the 2009 financial business plan.

The Committee has targeted a total cash bonus pool for achievement of the business priorities based on the sum of individual employee market-based target percentages ranging from approximately 3% to 50% of each employee's eligible earnings. Generally, eligible earnings are an employee's base salary and overtime pay. The Committee has discretion to adjust the cash bonus pool attributable to the business priorities based on accomplishment of the applicable objectives as determined by the Committee and the CEO. Funding of the Company's cash bonus pool and the payment of individual cash bonuses to employees are subject to the sole discretion of the Committee.

Exhibit 21.1

Targa Resources Partners LP Subsidiary List

Entity Name	Jurisdiction of Formation
Targa Intrastate Pipeline LLC	Delaware
Targa Louisiana Field Services LLC	Delaware
Targa Louisiana Intrastate LLC	Delaware
Targa North Texas GP LLC	Delaware
Targa North Texas LP	Delaware
Targa Resources Operating GP LLC	Delaware
Targa Resources Operating LP	Delaware
Targa Resources Partners Finance Corporation	Delaware
Targa Resources Texas GP LLC	Delaware
Targa Texas Field Services LP	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form Form S-8 (No. 333-149200) and Form S-3 (No. 333-151303) of Targa Resources Partners LP of our report dated February 25, 2009 relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 26, 2009

Exhibit 31.1

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Rene R. Joyce, certify that:

1. I have reviewed this Annual Report on Form 10-K of Targa Resources Partners LP;

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

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

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

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

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

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

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

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

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

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

Date: February 25, 2009

By: /s/ RENE R. JOYCE .
Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Jeffrey J. McParland, certify that:

1. I have reviewed this Annual Report on Form 10-K of Targa Resources Partners LP;

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

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

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

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

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

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

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

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

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

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

Date: February 25, 2009

By: /s/ Jeffrey J. McParland .
Name: Jeffrey J. McParland
Title: Executive Vice President, Chief Financial Officer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 32.1

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

In connection with the Annual Report on Form 10-K of Targa Resources Partners LP (the "Partnership") for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Rene R. Joyce, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ RENE R. JOYCE .
Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP

Date: February 25, 2009

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

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

In connection with the Annual Report on Form 10-K of Targa Resources Partners LP (the “Partnership”) for the year ended December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Jeffrey J. McParland, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ JEFFREY J. MCPARLAND .
Name: Jeffrey J. McParland
Title: Executive Vice President, Chief Financial Officer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP

Date: February 25, 2009

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.