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

Form 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2007

or

o **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:
Title of Class: None

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

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 **o** No ☑

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 ☑ No **o**

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. **o**

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

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

The aggregate market value of the Common Units representing limited partner interests held by non-affiliates of the registrant was approximately $644,684,000 on June 29, 2007, based on $33.50 per unit, the closing price of the Common Units as reported on The NASDAQ Stock Market LLC on such date.

At March 25, 2008, there were 34,652,000 Common Units, 11,528,231 Subordinated Units, and 942,455 General Partner Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

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DESCRIPTION

TARGA RESOURCES PARTNERS LP

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;
- 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;
- the amount of collateral required to be posted from time to time in our transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the gathering and processing industry;
- the timing and extent of changes in natural gas, NGLs and 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;
- our ability to grow through acquisitions or internal growth projects, and the successful integration and future performance of such assets;
- 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;
- general economic, market and business conditions; and
- the risks described elsewhere in this 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.

Forward-looking statements contained in this Annual Report and all subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by this cautionary statement.

As generally used in the energy industry and in this Annual Report on Form 10-K, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 gallons)
BBtu	Billion British thermal units
Bcf	Billion cubic feet
Btu	British thermal unit, 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(s)	Natural gas liquid(s)
Tcf	Trillion cubic feet

Price Index Definitions

GD-HH	Henry Hub Gas Daily average
IF-HH	Inside FERC Gas Market Report, Henry Hub
IF-HSC	Inside FERC Gas Market Report, Houston Ship Channel/Beaumont, Texas
IF-NGPL 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*

General

We are a growth-oriented Delaware limited partnership formed on October 26, 2006 by Targa Resources, Inc. (“Targa”), 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 NGLs and NGL products. We currently operate in the Fort Worth Basin/Bend Arch (the “Fort Worth Basin”) in north Texas, the Permian Basin of west Texas and in southwest Louisiana.

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. We acquired the assets of the SAOU System located in the Permian Basin (the “SAOU System”) and the assets of the LOU System located in southwest Louisiana (the “LOU System”) from Targa in October 2007.

We intend 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 growth 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, prudent risk management and growth through acquisitions and organic projects. We intend to accomplish this objective by executing the following strategies:

- *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 the active development and growing production 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, 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 significant portion of our expected natural gas, NGLs and condensate equity volumes for the years 2008 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.
- *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;

- where permitting, drilling and workover activity is high;
- with the potential for long-term acreage dedications;
- with a strong base of current production and the potential for significant future development; 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, as well as acquisitions in other related midstream businesses and/or expansion into new geographic areas of operation. 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.
- *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 is a large gatherer and processor of natural gas in the United States. 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 United States. Targa has an experienced and knowledgeable executive management team and experienced and knowledgeable commercial and operations teams. We believe Targa's relationships throughout the energy industry, including with producers of natural gas in the United States, 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. Current high levels of natural gas exploration, development and production activities within the Fort Worth Basin present significant organic growth 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 the ability to deliver natural gas to industrial users and electric utilities in the Lake Charles area. It 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 and efficient operation of our facilities.
- *Low maintenance capital expenditures.* We believe that a 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. This strategy reduces volumetric risk while managing commodity price risk related to these arrangements. We manage our business by hedging the commodity price exposure associated with a significant portion of our expected equity volumes of natural gas and NGLs in the near to mid-term.
- *Strong producer customer base.* We have a strong producer customer base consisting of both major oil and gas companies and independent 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 United States, 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 all of 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 has an experienced and knowledgeable executive management team with an average of 28 years in the energy industry that owns a 3.4% direct and indirect ownership interest in us. Targa's executive management team has a proven track record of enhancing value through the acquisition, optimization and integration of midstream assets. In addition, Targa's operations and commercial management team consists of individuals with an average of 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. These risks include the adverse impact of changes in natural gas and NGL prices on the amount we are able to distribute to you, our inability 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, please 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 United States. 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. and its affiliates ("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. At December 31, 2007, Targa had total assets of $3.8 billion (including the assets of the Partnership, which represent $1.5 billion of this amount).

Targa's businesses include:

Natural Gas Gathering and Processing Division — Targa gathers and processes natural gas from the Permian Basin in west Texas and southeast New Mexico and the offshore regions of the Texas and Louisiana Gulf Coast. 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 nine 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 the year ended December 31, 2007, these assets processed an average inlet plant volume of approximately 2 Bcf/d of natural gas and produced an average of approximately 107 MBbls/d of NGLs, in each case, net to Targa's ownership interests.

NGL Logistics and Marketing Division — Targa has a significant, integrated NGL logistics and marketing business with 16 storage, marine and transport terminals with an NGL above ground storage capacity of approximately 900 MBbls, net NGL fractionation capacity of approximately 300 MBbls/d and 43 owned and operated storage wells with a net storage capacity of approximately 62 MMBbl. 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 in southwest Louisiana and near Mont Belvieu, Texas, the primary NGL hub in the United States. 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, leases approximately 80 transport tractors and owns 100 tank trailers, and leases and manages approximately 800 railcars.

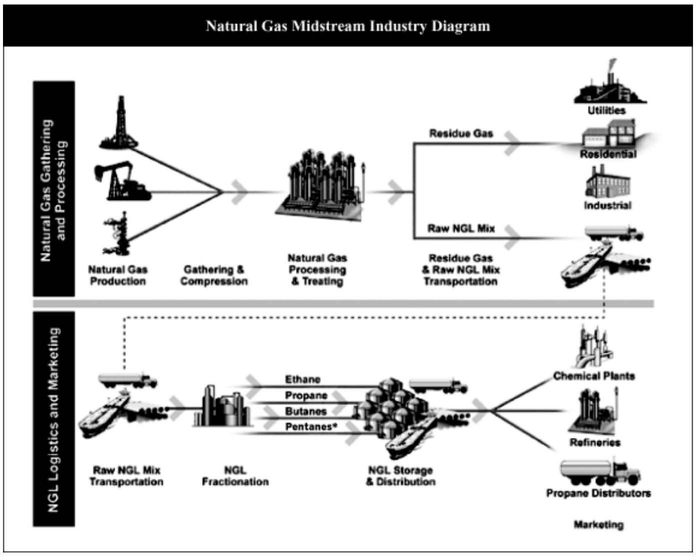
Targa has indicated that it intends to use us as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets. Over time, Targa intends to offer us the opportunity to purchase substantially all of its remaining businesses, 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 constantly 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. Please see "Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement". In addition, to carry out operations, our general partner and its affiliates, which are indirectly owned by Targa, employ approximately 920 people, some of whom provide direct support to our operations. We do not have any employees. Please see "Item 1. Business — 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. Please see "Item 13. — Certain Relationships and Related Transactions, and Director Independence — Conflicts of Interest".

Midstream Sector Overview

General. Natural gas gathering and processing is a critical part of the natural gas value chain. Natural gas gathering and processing systems create value by collecting raw natural gas from the wellhead and separating dry gas (primarily methane) from NGL such as ethane, propane, normal butane, isobutane and natural gasoline. Most natural gas produced at the wellhead contains NGL. Natural gas produced in association with crude oil typically contains higher concentrations of NGL than natural gas produced from gas wells. This "rich," unprocessed natural gas is generally not acceptable for transportation in the nation's interstate transmission pipeline system or for commercial use. Processing plants extract the NGL, leaving residual dry gas that meets interstate transmission pipeline and commercial quality specifications. Furthermore, they produce marketable NGL, which, on an energy equivalent basis, usually have a greater economic value as a raw material for petrochemicals and motor gasolines than as a component of the natural gas stream.



Gathering. At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport raw natural gas to a central location for processing and treating. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are often designed to be highly flexible to allow gathering of natural gas at different pressures, flowing natural gas to multiple plants and quickly connecting new producers, and most importantly scalable, to allow for additional production without significant incremental capital expenditures.

Compression. Since wells produce at progressively lower field pressures as they deplete, it becomes increasingly difficult to deliver the remaining production in the ground against a higher pressure that exists in the connecting gathering system. Natural gas compression is a mechanical process in which a volume of natural gas at a given pressure is compressed to a desired higher pressure, which allows the natural gas to flow into a higher pressure system. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher pressure system. If field compression is not installed, the remaining natural gas in the ground will not be produced because it cannot overcome the higher gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering natural gas that otherwise would not be produced.

Treating and Dehydration. After gathering, the second process in the midstream value chain is treating and dehydration. Natural gas contains various contaminants, such as water vapor, carbon dioxide and hydrogen sulfide, which can cause significant damage to intrastate and interstate pipelines and therefore render the gas unacceptable for transmission on such pipelines. In addition, end-users will not purchase natural gas with a high level of these contaminants. To meet downstream pipeline and end-user natural gas quality standards, the natural gas is dehydrated to remove the saturated water and is chemically treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.

Processing. Once the contaminants are removed, the next step involves the separation of pipeline quality residue gas from NGL, a method known as processing. Most decontaminated rich natural gas is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components. The removal and separation of hydrocarbons during processing is possible because of the differences in physical properties between the components of the raw gas stream. There are four basic types of natural gas processing methods, including cryogenic expansion, lean oil absorption, straight refrigeration and dry bed absorption. Cryogenic expansion represents the latest generation of processing, incorporating extremely low temperatures and high pressures to provide the best processing and most economical extraction.

Natural gas is processed not only to remove NGL that would interfere with pipeline transportation or the end use of the natural gas, but also to separate from the natural gas those hydrocarbon liquids that could have a higher value as NGL than as natural gas. The principal components of residue gas are methane and ethane but processors typically have the option either to recover ethane from the residue gas stream for processing into NGL or reject ethane and leave it in the residue gas stream, depending on whether the ethane is more valuable being processed or left in the natural gas stream. The residue gas is sold to industrial, commercial and residential customers and electric utilities. The premium or discount in value between natural gas and separated NGL is known as the “frac spread.” Because NGL often serve as substitutes for products derived from crude oil, NGL prices tend to move in relation to crude prices.

Natural gas processing occurs under a contractual arrangement between the producer or owner of the raw natural gas stream and the processor. There are many forms of processing contracts which vary in the amount of commodity price risk they carry. The specific commodity exposure to natural gas or NGL prices is highly dependent on the types of contracts. Processing contracts can vary in length from one month to the “life of the field.” Three typical processing contract types are described below:

- *Percent-of-Proceeds, or Percent-of-Value or Percent-of-Liquids.* In a percent-of-proceeds arrangement, the processor remits to the producers a percentage of the proceeds from the sales of residue gas and NGL products or a percentage of residue gas and NGL products at the tailgate of its processing facilities. In some percent-of-proceeds arrangements, the producer is paid a percentage of an index price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. The percent-of-value and percent-of-liquids are variations on this arrangement. These types of arrangements expose the processor to some commodity price risk as the revenues from the contracts are directly correlated with the price of natural gas and NGL.
- *Keep-Whole.* A keep-whole arrangement allows the processor to keep 100% of the NGL produced and requires the return of the processed natural gas, or value of the gas, to the producer or owner. A wellhead purchase contract is a variation of this arrangement. Since some of the gas is used during processing, the processor must compensate the producer or owner for the gas shrink entailed in processing by supplying additional gas or by paying an agreed value for the gas utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGL. As a result, a processor with these types of contracts benefits when the value of the NGL is high relative to the cost of the natural gas and is disadvantaged when the cost of the natural gas is high relative to the value of the NGL.
- *Fee-Based.* Under a fee-based contract, the processor receives a fee per gallon of NGL produced or per Mcf of natural gas processed. Under this arrangement, a processor would have no commodity price risk exposure.

Fractionation. Fractionation is the separation of the heterogeneous mixture of extracted NGL into individual components for end-use sale. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate products. As the temperature of the stream is increased, the lightest component boils off the top of the distillation tower as a gas where it then condenses into a purity liquid that is routed to storage. The heavier components in the mixture are routed to the next tower where the process is repeated until all components have been separated. A typical barrel of NGL consists of ethane, propane, normal butane, isobutane and natural gasoline. Described below are the five basic NGL components and their typical uses:

- *Ethane.* Ethane is used primarily as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.
- *Propane.* Propane is used as heating fuel, engine fuel and industrial fuel, for agricultural burning and drying and as petrochemical feedstock for production of ethylene and propylene.
- *Normal Butane.* Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with propane, and feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used to derive isobutane.
- *Isobutane.* Isobutane is principally used by refiners to enhance the octane rating of motor gasoline and in the production of MTBE, an additive in cleaner burning motor gasoline.
- *Natural Gasoline.* Natural gasoline is principally used as a motor gasoline blend stock or petrochemical feedstock.

Transportation and Storage. Once the raw natural gas has been conditioned or processed and the raw NGL mix fractionated into individual NGL components, the natural gas and NGL components are stored, transported and marketed to end-use markets. Both the natural gas industry and the NGL industry have hundreds of thousands of miles of intrastate and interstate transmission pipelines in addition to a network of barges, rails, trucks, terminals and storage to deliver natural gas and NGL to market. The bulk of the NGL storage capacity is located near the refining and petrochemical complexes of the Texas and Louisiana Gulf Coasts, with a second major concentration in central Kansas. Each commodity system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily supply-demand shifts.

Our Systems

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

Facility	County/Parish - Approximate Square Miles	Approximate Gross Processing Capacity (MMcf/d)	2007 Approximate Inlet Throughput Volume (MMcf/d)	2007 Approximate NGL Production (MBbl/d)	Process Type	Approximate Fractionation Capacity (MBbl/d)
Permian Basin						
Mertzon	Irion, TX	48	39.9	6.2	Cryo(2)	N/A
Sterling	Sterling, TX	62	48.6	7.9	Cryo(2)	N/A
Conger(1)	Sterling, TX	25	—	—	Cryo(2)	N/A
Gathering Area	10 counties - 4,000 square miles	135	88.5	14.1		
Louisiana Gulf Coast						
Gillis	Calcasieu, LA	180	149.4	8.6	Cryo(2)	13
Acadia	Acadia, LA	80	28.9	1.5	Cryo(2)	N/A
Gathering Area	12 parishes - 3,800 square miles	260	178.3	10.1		13
North Texas						
Chico	Wise, TX	265	152.1	17.2	Cryo(2)	12
Shackelford	Shackelford, TX	13	10.3	1.3	Cryo(2)	N/A
Gathering Area	14 counties - 2,500 square miles	278	162.4	18.5		12
Total Gathering and Processing		673	429.2	42.7		25

(1) 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.

(2) Cryo — Cryogenic Expander.

The North Texas System

The North Texas System consists of two gathering systems connected via a high-pressure 32-mile, 10-inch diameter pipeline (“the Interconnect Pipeline”). This interconnection between the gathering systems allows us to send natural gas in excess of the Shackelford plant processing capacity to the Chico plant. The gathering systems comprise approximately 4,000 miles of pipelines that, in aggregate, gather wellhead natural gas from approximately 2,700 meters for transport to the Chico and Shackelford natural gas processing facilities.

Gathering. The Chico Gathering System consists of approximately 1,950 miles of primarily low pressure gathering pipelines, which gathers natural gas from Denton, Montague, Wise, Clay, Jack, Palo Pinto and Parker counties on the eastern part of the North Texas System. The natural gas that is gathered on the Chico Gathering System is either delivered directly to the Chico plant, where it is compressed for processing, or is compressed in the field at approximately 26 compressor stations and then transported via one of several high-pressure gathering pipelines to the Chico plant.

The Shackelford Gathering System consists of approximately 2,050 miles of natural gas gathering pipelines, which gathers natural gas from Jack, Palo Pinto, Archer, Young, Stephens, Eastland, Throckmorton, Shackelford and Haskell counties on the western part of the North Texas System. The western and southern portions of the Shackelford Gathering System gather natural gas that is transported on intermediate-pressure gathering pipelines to the Shackelford plant. The approximately 15 MMcf/d of natural gas gathered from the northern and eastern portions of the Shackelford Gathering System are typically transported on the

Interconnect Pipeline to the Chico plant for processing. This natural gas is compressed at approximately 11 compressor stations to achieve sufficient pressure to enter the high pressure Interconnect Pipeline.

For the year ended December 31, 2007, the North Texas System gathered approximately 168 MMcf/d of natural gas.

Processing. The Chico processing plant is located in Wise County, Texas, approximately 45 miles northwest of Fort Worth, Texas. The Chico processing plant includes a state-of-the-art cryogenic processing train with a nameplate capacity of approximately 150 MMcf/d that was installed in 2002 and that has operated at throughputs of up to approximately 165 MMcf/d. The Chico processing plant's capacity was expanded by 100 MMcf/d in 2006, with the refurbishment of an idle processing train. Refrigeration capacity is currently installed to operate this train at full cryogenic recovery at half capacity or lower recoveries at higher volumes. This refurbished processing train ran at full capacity in June of 2007 during a turnaround of the primary processing train (the 165 MMcf/d train) at Chico. An additional electric drive refrigeration compressor that is on-site will be installed when needed, which will allow the refurbished processing train to recover NGLs up to its full design capacity. The Chico plant also includes a residue recompression turbine waste heat recovery system, which increases operating efficiency. The Chico plant also includes an NGL fractionator with the capacity to fractionate up to approximately 11,500 Bbls/d of raw NGL mix. This fractionation capability allows the Chico facility to deliver raw NGL mix to Mont Belvieu primarily through Chevron's WTLPG Pipeline or separated NGL products to local markets via truck.

Results of drilling in some areas such as Montague County indicate an increase in the carbon dioxide content of the gas. In response to this increase in carbon dioxide, we are refurbishing a carbon dioxide treater which will increase the Co2 removal capacity to 4,200 Mcf/day.

The Shackelford natural gas processing plant is located in Shackelford County, Texas near Albany, Texas which is approximately 120 miles west of Fort Worth, Texas. 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.

Market Access. The Chico processing plant's location in northeastern Wise County provides us and producers with several options for both NGL and residue gas delivery. The primary outlet for NGLs is Chevron's WTLPG Pipeline which delivers volumes from the Chico plant to Mont Belvieu for fractionation. NGL products produced at the Chico processing facility can be transported via truck to local or other markets. For 2007, approximately 409,000 gallons per day of NGLs were delivered from the Chico processing facility by pipeline and approximately 124,000 gallons per day of NGL products were delivered from the Chico processing facility by truck.

Low pressure condensate is composed of heavy hydrocarbons which condense in the gathering system and are collected in low pressure separators associated with field compressors and in low pressure separators upstream of the processing plants. This product is collected and shipped by truck from various locations in the system and sold as condensate at oil related index prices. High pressure condensate is a mix of intermediate and heavy hydrocarbons which condense in the high pressure gathering lines between the compressor stations and the processing plants. This condensate is collected in high pressure separators prior to the plant and shipped via high pressure trucks to an injection point on the WTLPG Pipeline at Bridgeport for shipment to Mont Belvieu, where it is sold as NGLs. Occasionally, this high pressure condensate product is shipped via truck directly to Mont Belvieu.

Our connections to multiple interstate and intrastate natural gas pipelines give the Chico plant and its customers the ability to maximize realized prices by accessing major trading hubs and end-use markets throughout the Gulf Coast, Midwest and northeast regions of the United States. Currently, residue gas is shipped via the:

- Natural Gas Pipeline Company of America which is owned by Kinder Morgan, Inc. and serves the Midwest, specifically the Chicago market;

- ET Fuel System which is owned by Energy Transfer Partners, L.P. and has access to the Waha, Carthage and Katy hubs in Texas;
- Atmos Pipeline — Texas ("Atmos-Texas") which is owned by Atmos Energy Corporation and has access to the Waha, Carthage and Katy hubs in Texas; and
- Enbridge Pipelines (North Texas) L.P. which is owned by Enbridge Energy Partners, L.P. and has access to several local residue gas markets.

Residue natural gas from the Shackelford processing plant is delivered to the Carthage and Katy hubs on Atmos-Texas and NGLs from the plant are delivered to Mont Belvieu on the WTLPG Pipeline. Condensate from the Shackelford System is handled similarly to the description above for the Chico System.

Targa Intrastate Pipeline. Targa Intrastate Pipeline LLC ("Targa Intrastate"), our wholly-owned subsidiary, holds a 41-mile, 6-inch diameter intrastate pipeline that transports natural gas from the Shackelford processing plant to an interconnect with Atmos-Texas and a 1.65 mile, 10-inch diameter intrastate pipeline that transports natural gas through part of the Chico System in Denton County, Texas. Targa Intrastate is regulated by the Railroad Commission of Texas ("RRC").

Competition. In North Texas, our gathering, processing and fractionation system competes with several systems located in the Fort Worth Basin. Our competitors include but are not limited to gathering and processing systems owned by Devon Energy Corp ("Devon"), Enbridge Energy Partners, L.P. ("Enbridge"), J-W Operating Company, Davis Gas Processing Inc., Hanlon Gas Processing, Ltd. and Upham Oil and Gas Company. A number of the gathering and processing competitors in the region are smaller entities with assets serving a particular field, producer or limited area but lack a basin-wide presence. As for the larger competitors, Devon and Enbridge's operations are the most extensive and are closest in proximity to our area of operations, based on publicly available information. Devon's processing capacity is greater than ours, while Enbridge's is approximately the same. Currently, Devon almost exclusively gathers and processes its own production. Competition within the Fort Worth Basin may increase as new ventures are formed or as existing competitors expand their operations. Competitive factors include processing and fuel efficiencies, operational costs, commercial terms offered to producers and capital expenditures required for new producer connections, along with the location and available capacity of gathering systems and processing plants.

Customers and Contracts. The North Texas System gathers and processes natural gas for approximately 430 customers. For the year ended December 31, 2007, natural gas received from ConocoPhillips represented approximately 33% of the North Texas System volumes. No other customer represented over 10% of the North Texas System volumes. This diverse customer base enhances the stability of our volumes.

In North Texas, we have a long-term strategic relationship with ConocoPhillips, which is our largest producer by volume. Subject to limited exceptions, substantially all of ConocoPhillips' current production from leases covering an approximately 30,000 acre area in Wise and Denton counties has been committed to us for gathering and processing through a prior agreement with Burlington Resources entities. ConocoPhillips is under no obligation to deliver minimum volumes or to continue to develop its leasehold position under its agreement with us. This commitment extends through 2015, with a ten year renewal, at ConocoPhillips' option. The North Texas System has no other significant customers. Our producer contracts in north Texas are primarily percent-of-proceeds and most have a remaining term greater than 3 years or a term for life-of-lease. A portion of our existing contracts on the North Texas System are in the evergreen portion of their term, meaning that the original term of these contracts has expired and that they will continue to roll-over on an on-going basis until either party elects to discontinue the contract. Our experience is that we retain, and sometimes renegotiate, essentially all of these contracts.

The SAOU System

The SAOU System consists of approximately 1,350 miles of pipeline in the Permian Basin of west Texas and the Mertzon, Sterling and Conger processing plants. The broad geographic scope of the SAOU System, covering portions of 10 counties and approximately 4,000 square miles in west Texas, and proximity to production and development provides us the ability to connect new wells and to process additional natural gas in our existing processing plants.

Gathering. The SAOU System is connected to approximately 3,000 producing wells and/or central delivery points. For the year ended December 31, 2007, the system gathered approximately 94 MMcf/d of natural gas. The system has approximately 850 miles of low-pressure gathering systems. The system also contains approximately 500 miles of high-pressure gathering pipelines to deliver the natural gas to its processing plants. The gathering system has 27 compressor stations to inject low-pressure gas into these high-pressure pipelines.

Processing. The SAOU System includes two currently operating processing plants. The Mertzon plant and the Sterling plant, both of which are refrigerated cryogenic plants, have aggregate processing capacity of approximately 110 MMcf/d. The system also includes the Conger cryogenic plant with a capacity of approximately 25MMcf/d, which is on standby and can be quickly reactivated on short notice to meet additional needs for processing capacity.

Market Access. The Mertzon processing plant currently delivers residue gas to Kinder Morgan Texas Pipeline, L.P.'s Rancho pipeline and to Northern Natural Gas Company. NGLs produced by the plant are delivered to a pipeline owned by TEPPCO Partners, L.P. that transports the NGLs to Cedar Bayou Fractionators ("CBF," in which Targa owns an interest) located at the Mont Belvieu hub. The Sterling processing plant has residue gas connections to pipelines owned by affiliates of Atmos Energy Corporation, El Paso Natural Gas Company, ONEOK and Enterprise Products Partner LP ("Enterprise")/ET Fuel Pipeline, L.P., and NGLs are delivered to the West Texas LPG pipeline, owned by Chevron, which also delivers to CBF at the Mont Belvieu hub.

Competition. The SAOU System competes primarily with Davis Gas Processing to the south and southwest, DCP Midstream LLC to the north and Atlas Gas Pipeline Company, formerly Western Gas Resources, Inc., to the west. Several of the processing plants that compete with the SAOU System are very near or at full capacity. The SAOU System, with its remaining excess capacity of approximately 20 MMcf/d at the Sterling and Mertzon plants and 25 MMcf/d available for reactivation at the Conger plant, has the ability to process new volumes of gas in proximity to its gathering system without requiring significant capital expenditures. Consistent with other gathering and processing systems, competitive factors for the SAOU System include processing and fuel efficiencies, operational costs, commercial terms offered to producers and capital expenditures required for new producer connections, along with the location and available capacity of gathering systems and processing plants.

Customers and Contracts. For the year ended December 31, 2007, the SAOU System's major customers include Range Production Company, TXP, Inc. and Chevron, representing approximately 25%, 18% and 15% of the SAOU System's volumes. No other customer represented more than 10% of the SAOU System's volumes. The producer contracts under which the SAOU System operates are primarily percent-of-proceeds based contracts and most have a remaining term greater than 3 years. A portion of our existing contracts on the SAOU System are in the evergreen portion of their term. Our experience is that we retain, and sometimes renegotiate, essentially all of these contracts.

The LOU System

The LOU System consists of approximately 600 miles of gathering system pipelines, covering approximately 3,800 square miles in southwest Louisiana between Lafayette and Lake Charles, the Gillis and Acadia processing plants and an intrastate pipeline system.

Gathering. The LOU System is connected to approximately 200 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. For the year ended December 31, 2007, the gathering system gathered approximately 191 MMcf/d of natural gas.

Processing. The processing plants are the Gillis and Acadia processing plants. The Gillis plant is a refrigerated cryogenic plant. These processing plants have an aggregate processing capacity of approximately 260 MMcf/d. Natural gas can be readily moved between the Gillis and Acadia plants in order to optimize operational efficiencies, meet customer needs and improve profitability.

Raw NGL mix from the Acadia plant is transported to, and combined with raw NGL mix from the Gillis plant via the system's pipelines, with fractionation occurring at the integrated fractionation facility at the Gillis plant. Excess raw NGL mix can also be transported to Targa's Lake Charles fractionation facility. The operating capacity of the Gillis fractionator is approximately 13 MBbls/d. Component NGL products are delivered from the Gillis fractionator via the system's pipelines to local or other markets via pipeline, truck and/or barge.

Market Access. 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, which currently consume approximately 500 MMcf/d of natural gas, through both medium-pressure and high-pressure pipelines. As a result of the flexibility of these intrastate pipeline assets and the reliability of the system's natural gas supplies in the area, the system has a significant market share in the Lake Charles industrial market. Most of the major customers have contracts with terms of one year or more; the remainder are multi-month contracts. In addition to access to the Lake Charles market, the Acadia plant also has the ability to deliver high-pressure residue gas to attractive markets throughout the United States by accessing the Trunkline, Transco, Tennessee, Columbia Gulf and GulfSouth pipelines. The location of the intrastate pipeline serving the Lake Charles market and the ability of LOU's gathering system to interconnect with other pipelines carrying processable gas, positions the LOU System and the market to benefit from other supply sources, including imported LNG. Currently, there are a number of LNG regasification plants that are either operating or have been approved by either the Federal Energy Regulatory Commission ("FERC") or Coast Guard for construction along the Gulf Coast in close proximity to the system.

Competition. The LOU System is crossed by numerous interstate and intrastate pipelines. The primary competition for wellhead gas production is with the intrastate pipeline systems owned by Crosstex Gulf Coast Marketing, LTD ("Crosstex") and Enterprise along the eastern portion of the LOU System, particularly in Lafayette and Vermilion Parishes. The LOU System has traditionally been viewed favorably by producers for quick, reliable connections and flexible purchase and processing options. Interstate pipelines generally bringing gas from offshore, although more numerous and more broadly situated across southwest Louisiana, provide some level of competition but are not considered to be pipelines preferred by onshore producers due to high connection costs, longer lead times for connections and agreements, and more restrictive quality requirements. For the industrial customers in the Lake Charles Market, the primary competitors include GulfSouth Pipeline Company, LP, which utilizes local production as well as LNG sourced gas, Varibus Pipeline, utilizing connections to four interstate pipelines, and a Texaco/Chevron pipeline delivering gas from an interstate pipeline. The LOU System has a long history of providing reliable supply for these industrial customers. Consistent with other gathering and processing systems, competitive factors for the LOU System include processing and fuel efficiencies, operational costs, commercial terms offered to producers and capital expenditures required for new producer connections, along with the location and available capacity of gathering systems and processing plants.

Customers and Contracts. For the year ended December 31, 2007, no individual producer represented more than 10% of the LOU System's volumes. The LOU System's producer contract mix is primarily percent-of-liquids (approximately 57% by volume) and to a lesser extent short term wellhead purchase and keep whole contracts (approximately 43% by volume). In addition, there is a gas gatherer who is a significant supplier to the system and sells gas to us on a spot basis. This gatherer delivered approximately 26% of the LOU System's volumes in 2007. The LOU System's industrial customers' ability to readily burn richer (higher Btu) gas provides the system with operational and commercial flexibility to process less NGLs from the gas stream. Unlike almost any other gathering and processing system, the Gillis plant has a residue tailgate that directly serves the Lake Charles industrial market and this market readily and easily burns higher Btu gas (more NGLs left in the gas stream). If NGL prices are significantly lower than their value as natural gas, then we have the ability to not remove the NGLs, selling them instead in the natural gas stream. A majority of our existing contracts on the LOU System are in the evergreen portion of their term. Our experience is that we retain, and renegotiate, essentially all of these contracts.

The Combined Systems. Our aggregate gas supply contract profile for the year ended December 31, 2007 is approximately 79% percent-of-proceeds contracts, approximately 19% wellhead purchase/keep whole contracts, approximately 1% fee-based contracts on a volume basis and approximately 1% hybrid contracts. Substantially all of the wellhead and keep-whole contracts are associated with a portion of the LOU System's contracts. The LOU System's industrial customers that burn the Gillis plant residue gas readily burn richer (higher Btu) gas, thereby providing the system with operational and commercial flexibility to process less NGLs from the gas stream if unexpected operating conditions occur or if NGLs are more valuable as natural gas. Such volumes are typically under short term contracts. The above factors mitigate the commodity price risk typically associated with wellhead purchase or keep-whole contracts. In addition, our largest natural gas suppliers for the year ended December 31, 2007 were ConocoPhillips and Crosstex, who accounted for approximately 12% and 11%, respectively, of our supply. Approximately half of the gas supply contracts by volume have a remaining term greater than 3 years, a term for life of lease, or have been in evergreen status for more than three years.

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 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 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. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. 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 services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (“the Competition Bill”) and H.B. 1920 (“the LUG Bill”). The Competition Bill gives the 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. It 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 Bill modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. It 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. Both the Competition Bill and the LUG Bill became effective September 1, 2007. We cannot predict what effect, if any, either the Competition Bill or the LUG Bill might have on our operations in Texas.

Intrastate Pipeline Regulation

Our Texas intrastate pipeline, 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 has a tariff on file with the RRC.

Our Louisiana intrastate pipeline, Targa Louisiana Intrastate LLC, 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 most FERC jurisdiction.

Our intrastate NGL pipelines in Louisiana, gather raw NGL streams that we own from our processing plants in Louisiana to our fractionator in Lake Charles, Louisiana, where the raw NGL streams are fractionated into various products. These pipelines are not subject to FERC regulation or rate regulation by the DNR, but are regulated by DOT safety regulations.

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.

As discussed above in the context of Gathering Pipeline Regulation, the Competition Bill and the LUG Bill also contain provisions applicable to intrastate transportation pipelines. We cannot predict what effect, if any, either the Competition Bill or the LUG Bill might have on our operations in Texas.

Natural Gas Processing

Our natural gas processing operations are not presently subject to FERC regulation. However, there can be no assurance that our processing operations will continue to be exempt from FERC regulation in the future.

Our processing facilities are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation can be subject to extensive federal regulations, and in Texas and Louisiana, 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.

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. On June 15, 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 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 the FERC and/or the Commodity Futures Trading Commission (“CFTC”). Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Our sales of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. As noted above, 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 natural gas and NGL marketing operations, and we do not believe that we would be affected by any such FERC action materially differently than other natural gas and NGL marketers with whom we compete.

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, please see “Item 1A. Risk Factors — Risks Related to Our Business”.

Other Federal Laws and Regulation Affecting Our Industry

Energy Policy Act of 2005

On August 8, 2005, President Bush signed into law the Domenici-Barton Energy Policy Act of 2005 (“EP Act 2005”). The 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 increases the FERC’s civil penalty authority under the NGPA from $5 thousand per violation per day to $1 million per violation per day. The civil penalty provision are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of EP Act 2005, and subsequently denied rehearing. The rules make 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 to make any such 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. The new anti-market manipulation rule 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. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

FERC Standards of Conduct for Transmission Providers

Since 2002, FERC has been engaged in a lengthy process of revising its standards of conduct that regulate the manner in which interstate natural gas pipelines and certain natural gas storage companies which provide storage services in interstate commerce (defined as "Transmission Providers") may interact with certain affiliated entities. Delay in the revision process has resulted from a disagreement on the appropriate scope of affiliate relationships to be governed by the revised standards. In response to a remand in late 2006 from the United States Court of Appeals for the District of Columbia Circuit vacating the FERC's last series of affiliate standards of conduct (the "Energy Affiliate Rules"), the FERC issued on March 21, 2008, a notice of proposed rulemaking ("NOPR") proposing to change the approach of its standards of conduct from a corporate functional approach to an employee functional approach. The NOPR proposes to regulate the interactions between employees, either employed by a Transmission Provider or one of its affiliates, performing a natural gas transmission function and employees, either employed by a Transmission Provider or one of its affiliates, performing a natural gas marketing function. While we do not believe that our operations would be affected by the new standards of conduct as proposed, we have no way to predict with certainty the scope of the final standards of conduct that FERC may adopt.

FERC Market Transparency Rulemakings

On April 19, 2007, FERC issued a NOPR in which it proposed to require intrastate natural gas pipelines, which may include both gathering and transportation pipelines, to post daily on their Internet websites the actual volumes flowing on their systems. In addition, FERC proposed to require all buyers and sellers of more than a minimum volume of natural gas to report to FERC on an annual basis the number and total volume of their transactions. FERC has asserted that it has the jurisdiction to issue these regulations with respect to intrastate pipelines and otherwise non-jurisdictional buyers and sellers of gas in order to facilitate market transparency in the interstate natural gas market pursuant to Section 23 of the NGA, which was added by Section 316 of EP Act 2005. FERC has bifurcated the two issues, issuing a new NOPR on pipeline posting requirements on December 21, 2007, and a final rule on the annual natural gas transaction reporting requirements (Order 704), on December 26, 2007.

Under Order No. 704, wholesale buyers and sellers of more than a minimum volume of natural gas 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. In such report, buyers and sellers must categorize volumes reported as fixed price or index-based. FERC retreated from its earlier position that would have also required reporting of the number of transactions as well as the volumes. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's Policy Statement on price reporting. Several parties have filed requests for clarification or rehearing that are currently pending before FERC.

Under the revised NOPR on pipeline posting requirements, FERC is proposing to require intrastate pipelines to post daily actual and scheduled flows on an Internet website. FERC has suggested certain exemptions from the proposed rule such as an annual throughput minimum, an exemption for pipelines that lie entirely upstream of gas processing plants and an exemption for pipelines that deliver ninety-five percent (95%) or more of their gas to end-users. At the same time, FERC has also proposed to require that interstate pipelines add actual daily volumes to their Internet websites. Currently, interstate pipelines are only required to post design capacity, scheduled volumes and operationally available capacity. FERC has received comments on the revised NOPR on pipeline posting requirements, but has not yet issued a final rule. While we do not believe that our operations will be affected by the new posting requirements as proposed materially any differently than other midstream natural gas companies with whom we compete, we have no way to predict with certainty the scope of the final requirements that FERC may adopt.

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 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 governing the discharge of materials into the environment or otherwise relating to the protection of the environment. Please 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 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 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 this trend 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 Comprehensive Environmental Response, Compensation, and Liability Act, 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 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 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 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. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as "hazardous wastes" and therefore be subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease, and have in the past owned or leased, properties where hydrocarbons are being or have been handled for many years. 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) or 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 as a result of our review or in connection with maintaining 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

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the United States Congress is actively considering legislation to reduce emissions of greenhouse gases. One bill recently approved by the United States Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act or S.2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. The Lieberman-Warner bill proposes a “cap and trade” scheme of regulation of greenhouse gas emissions — a ban on emissions above a defined reducing annual cap. Covered parties will be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. Debate and a possible vote on this bill by the full Senate are anticipated to occur before mid-year 2008. In addition, at least 17 states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring either 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. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved. 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. Although we would not be impacted to a greater degree than other similarly situated transporters 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 transport.

Also, as a result of the United States Supreme Court’s decision on April 2, 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 EPA has publicly stated its goal of issuing a proposed rule to address carbon dioxide and other greenhouse gas emissions from vehicles and automobile fuels but the timing for issuance of this proposed rule has not been finalized by the agency. The Court’s holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act’s definition of “air pollutant” may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New federal or state restrictions on emissions of carbon dioxide 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 transport.

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 United States. 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 can impose substantial civil and criminal penalties for non-compliance. State laws for the control of water pollution may also provide varying civil and criminal penalties and liabilities. We believe that we are in substantial compliance with the requirements of the CWA and analogous state laws.

The Oil Pollution Act of 1990, as amended (“OPA”), which amends and augments the Clean Water Act, 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 vessels, including barges, offshore platforms, and onshore facilities, such as our pipelines and marine terminals. Under OPA, owners and operators of vessels and shore 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 Clean Water Act, 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, or 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. 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 existing 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 the DOT under the Pipeline Safety Improvement Act of 2002, which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006. The DOT, through the Pipeline and Hazardous Materials Safety Administration, or 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. The DOT also is required by the Pipeline Inspections, Protection, Enforcement, and Safety Act of 2006 to issue new regulations that set forth safety standards and reporting requirements applicable to low stress pipelines and gathering lines transporting hazardous liquids, including NGLs and condensate. A final rule addressing safety standards for hazardous liquid low-stress pipelines and gathering lines is anticipated to be issued by PHMSA in 2008. These safety standards may include applicable integrity management program requirements.

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 $0.3 million for years 2008 through 2010 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.

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 Environmental Protection Agency (“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.

Other Laws and Regulations

In addition, our operations and the operations of the natural gas and oil industry in general may be subject to laws and regulations regarding the security of industrial facilities, including natural gas and oil facilities. The Department of Homeland Security Appropriations Act of 2007 required the Department of Homeland Security (“DHA”) to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present “high levels of security risk.” The DHS issued an interim final rule, known as the Chemical Facility Anti-Terrorism Standards interim rule, in April 2007 regarding risk-based performance standards to be attained pursuant to the act and on November 20, 2007 further issued an Appendix A to the interim rule that established the chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules.

In January 2008, we prepared and submitted to the DHS initial screening surveys for facilities operated by us that possess regulated chemicals of interest in excess of the Appendix A threshold levels. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. Because we are currently awaiting a response from DHS on the extent to which some or all of our surveyed facilities may be determined to present a high level of security risk, the associated costs for complying with this interim rule has not been determined by us, and it is possible that such costs ultimately could be substantial.

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 920 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 the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available 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

Our cash flow is affected by supply and demand for natural gas and NGL products, 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 will be materially adversely affected if we experience significant, prolonged pricing deterioration below general price levels experienced over the past few years in our industry. 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;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, liquified natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;

- the availability of local, intrastate and interstate transportation systems;
- the availability and marketing of competitive fuels;
- the impact of energy conservation efforts; and
- the extent of governmental regulation and taxation.

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, 2007, our percent-of-proceeds arrangements accounted for approximately 79% 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 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 price of natural gas, NGLs and crude oil fluctuates. For additional information regarding our hedging activities, please 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 the 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 supplies. Additionally, our profitability is materially affected by the volume of raw NGL mix fractionated at our fractionation facilities. A material decrease in natural gas production from producing areas that we rely on for raw NGL mix, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of NGL products delivered to our fractionation facilities. Our ability to obtain additional sources of natural gas depends in part on the level of successful drilling activity near our gathering systems.

We have no control over the level of drilling 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 and 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 activity generally decreases as oil and natural gas prices decrease. In the past, the prices of natural gas have been extremely volatile, and we expect this volatility to continue. In the past, the prices of natural gas have been extremely volatile, and we expect this volatility to continue. Natural gas prices reached historic highs in 2005 and early 2006, but declined substantially in the second half of 2006 and continued to decline until late August 2007. Reductions in exploration or production activity or shut-ins by producers in the areas in which we operate as a result of a sustained decline in natural gas prices would lead to reduced utilization of our gathering and processing assets.

Because of these factors, even if new natural gas reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. If, due to reductions in drilling activity or competition, we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, throughput on our pipelines and the utilization rates of our treating, processing and fractionation facilities would decline, which could reduce our revenue and 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 derivative financial instruments, 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. The derivative instruments we utilize for these hedges are based on posted market prices, which may be 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. As a result of these 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. 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. For additional information regarding our hedging activities, please see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk".

We depend on one natural gas producer for a significant portion of our supply of natural gas. The loss of this customer or the replacement of its 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 the year ended December 31, 2007 was ConocoPhillips, who accounted for approximately 12% of our supply. In addition, there is a gas gatherer who is a significant supplier to the system and sells gas to us on a spot basis. This gatherer delivered approximately 11% of our system's volumes in 2007. 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 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 pipelines and other facilities become partially or fully unavailable to transport natural gas and NGLs, or if the gas quality specifications for their pipelines or facilities change so as to restrict our ability to transport gas on those pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

We depend on our Chico plant in north Texas and our Gillis plant in southwest Louisiana for a substantial portion of our revenues and if those revenues were reduced, there would be a material adverse effect on our results of operations and ability to make distributions to unitholders. To a similar but lesser degree, we are dependent on other gathering and processing systems, such as Mertzon, and Sterling.

Any significant curtailment of gathering, compressing, treating, processing or fractionation of natural gas at our Chico plant, Gillis plant or at our other plants could result in our realizing materially lower levels of revenues and cash flow for the duration of such curtailment. For the year ended December 31, 2007, our Chico and Gillis plant inlet volumes each accounted for approximately 35% of our total plant inlet volumes. Operations at our Chico plant, Gillis plant or our other plants could be partially curtailed or completely shut down, temporarily or permanently, as a result of:

- competition from other systems that may be able to meet producer needs or supply end-user markets on a more cost-effective basis;
- operational problems such as catastrophic events at a processing plant or our gathering lines, labor difficulties or environmental proceedings or other litigation that compel cessation of all or a portion of the operations at a plant or on a system;
- an inability to obtain sufficient quantities of natural gas for a system at competitive terms; or
- reductions in exploration or production activity, or shut-ins by producers in the areas in which we operate.

The magnitude of the effect on us of any curtailment of operations will depend on the length of the curtailment and the extent of the operations affected by such curtailment. We have no control over many of the factors that may lead to a curtailment of operations.

In addition, our business interruption insurance is subject to limitations and deductibles. If a significant accident or event occurs at our Chico plant or the Mertzon, Sterling and Gillis plants and their respective gathering systems that is not fully insured, it could adversely affect our operations and financial condition.

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

Acquisitions may significantly increase the size of the Partnership 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. At February 29, 2008, the corporate credit ratings of Targa as assigned by Moody's and Standard & Poor are B1 and B, respectively, 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.

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 the 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 petrochemical 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 to you.

We 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 heating industries could materially adversely affect our business, results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general economic conditions, new government regulations, reduced demand by consumers for products made with NGL products, increased competition from petroleum-based products due to pricing differences, mild winter weather 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 producers to leave the ethane in the natural gas stream thereby reducing the volume of NGLs delivered for fractionation and marketing. We have experienced periods where natural gas producers have retained ethane in the natural gas stream and may experience such periods in the future.

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, 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.

Any reduced demand for ethane, propane, normal butane, isobutane or natural gasoline 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 facilities are located, which could disrupt our operations.

We do not own most of the land on which our pipelines and 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 delays in our operations and, in some cases, work stoppages. For example, natural gas sales volumes for the first six months of 2007 were negatively impacted by unseasonably wet weather, which limited our ability to complete connections to new wells. Any similar delays or work stoppages caused by the weather could adversely affect our operating results for the affected periods.

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 and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of our related operations. 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, in the case of Hurricane Rita, 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. Our insurance is provided under Targa's insurance programs. 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 those considered to be sudden and accidental. If a significant accident or event occurs that is not fully insured, it could adversely affect our operations and financial condition. In addition, Targa may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. Moreover, significant claims by Targa may limit or eliminate the amount of insurance proceeds available to us. 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. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2007, we had approximately $626.3 million of borrowings outstanding under our amended credit facility. Our level of debt could have important consequences for us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- we need a portion of our cash flow to make interest payments on our debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders;

- our debt level makes us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

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, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources".

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, 2007, we had approximately $626.3 million of debt outstanding under our amended credit facility at variable interest rates. In December 2007, we entered into interest rate swaps with notional amounts of $200 million. Our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates. Please see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Interest Rate Risk".

Restrictions in our amended 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 amended credit facility contains covenants limiting our ability to make distributions, incur indebtedness, grant liens, and engage in transactions with affiliates. Furthermore, our amended credit facility contains covenants requiring us to maintain a ratio of consolidated indebtedness to consolidated EBITDA initially of not more than 5.00 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 amended 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 amended credit facility, please 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.

In addition, we are experiencing increased competition for the types of assets we contemplate purchasing. Increased competition for a limited pool of assets could result in our losing to other bidders more often or acquiring assets at less attractive prices. Either occurrence would 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 regulations or an accidental release of hazardous substances or hydrocarbons 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. Please see “Item 1. Business — Our Systems”. 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 other 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 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. Please see “Item 1. Business — Environmental, Health and Safety 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.

Section 1(b) of the Natural Gas Act of 1938 (“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, FERC regulation still affects our gas gathering operations and the markets for products related to these operations. FERC has recently issued a final rule requiring certain intrastate pipelines, including gathering facilities engaged in natural gas transactions, to submit annual reports to FERC. In addition, FERC has recently proposed to require certain intrastate pipelines to post daily scheduled and actual flows on their lines.

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, please 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 Energy Policy Act of 2005 ("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 operations have traditionally not been subject to FERC regulation, FERC has recently adopted and proposed regulations that may subject certain of our facilities to reporting and 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, please 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, the DOT, through the Pipeline and Hazardous Materials Safety Administration ("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.

We currently estimate that we will incur an aggregate cost of approximately $0.3 million between 2008 and 2010 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 this 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.

The PHMSA also is required by the Pipeline Inspections, Protection, Enforcement, and Safety Act of 2006 to issue new regulations that set forth safety standards and reporting requirements applicable to low stress pipelines and gathering lines transporting hazardous liquids, including NGLs and condensate. A final rule addressing safety standards for hazardous liquid low-stress pipelines and gathering lines is anticipated to be issued by PHMSA in 2008. These safety standards may include applicable integrity management program requirements.

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.

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 $0.3975 per common unit and subordinated unit per complete quarter, or $1.59 per unit per year, we will require available cash of approximately $18.7 million per quarter, or $74.9 million per year, based on common units and subordinated units outstanding at December 31, 2007. 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 non-appealable 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. Please 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 of 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 96,152 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. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, 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, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes, 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 or any other matter affecting us. 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 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 United States 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. 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 that a termination occurred.

You may be subject to foreign, 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 might be subject to return filing requirements and other taxes, including foreign, 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 United States federal, foreign, state and local tax returns.

Item 1B. *Unresolved Staff Comments*

None

Item 2. *Properties*

A description of our properties is contained in Item 1 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 LLC, 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. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit. WTG’s motion to reconsider and for a new trial was overruled. On January 2, 2008, WTG filed a notice of appeal. Targa will contest any appeal filed by WTG, but can give no assurances regarding the outcome of the proceeding.

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. Please see “Item 1. Business — Regulation of Operations and Environmental 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 the NASDAQ, as well as the amount of cash distributions declared per quarter for the period from February 14, 2007, the closing of our IPO, through December 31, 2007.

Quarter Ended	High	Low	Distribution per Common Unit	Distribution per Subordinated Unit
December 31, 2007	$29.84	$25.10	$ 0.3975	$ 0.3975
September 30, 2007	35.00	24.39	0.3375	0.3375
June 30, 2007	35.28	27.70	0.3375	0.3375
February 14, 2007 to March 31, 2007	29.30	22.75	0.16875	0.16875

As of March 11, 2008, there were approximately 40 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.

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 will distribute to the holders of common units and subordinated units on a quarterly basis 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.

Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Description of Credit Agreement” for a discussion of the restrictions included in our credit agreement that may restrict our ability to make distributions.

During 2007, we distributed to the holders of our common units and subordinated units on a quarterly basis a quarterly distribution of $0.3375 per unit, or $1.35 per year. For the fourth quarter of 2007, a distribution of $0.3975 per unit, or $1.59 per unit on an annualized basis, was declared on January 24, 2008, and was paid on February 14, 2008.

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 942,128 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.

Sales of Unregistered Units

None

Repurchase of Equity by Targa Resources Partners LP

None

Use of Proceeds

Not applicable.

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

SELECTED FINANCIAL AND OPERATING DATA

On February 14, 2007, we had Targa's ownership interests in the North Texas System contributed 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).

Although 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, as all of the North Texas System's equity accounts were also carried forward intact initially, and subsequently adjusted due to the cash consideration we paid for the acquired net assets.

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 consolidated financial statements and all other financial information included in this report have been restated to assume that the transfer of the North Texas System net assets from Targa to us had occurred at the date when both the North Texas System and the SAOU and LOU Systems met the accounting requirements for entities under common control (October 31, 2005). As a result, financial statements and financial information presented for prior periods in this report have been restated.

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

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 the year ended December 31, 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, combined with the acquisition-related activities of Targa for the period from January 1 to April 15, 2004. The selected combined financial and operating data of the predecessor for the three and a half months ended April 15, 2004 and as of and for the year ended December 31, 2003 are derived from the audited financial statements of the predecessor business.

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 Form 10-K. Please 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.

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As used in this report, unless we indicate otherwise, the terms "our," "we," "us" and similar terms refer to Targa Resources Partners LP, together with our subsidiaries, and the term "Targa" refers to Targa Resources, Inc. and its subsidiaries and affiliates (other than us). The following table summarizes selected financial and operating data for the periods and as of the dates indicated.

	Years Ended December 31, 2007	2006	2005	March 12 (Inception) through December 31, 2004	SAOU/LOU Systems Predecessor: 106-Day Period Ended April 15, 2004	Year Ended December 31, 2003
	(in millions of dollars, except operating and price data)					
Statement of Operations Data:						
Revenues	$ 1,661.5	$ 1,738.5	$ 1,172.5	$ 602.6	$ 232.8	$ 724.7
Product purchases	1,406.8	1,517.7	1,061.7	544.9	212.3	665.4
Operating expense	50.9	49.1	24.4	15.3	7.9	23.2
Depreciation and amortization expense	71.8	69.9	23.1	10.4	3.8	12.9
General and administrative expense	18.9	16.1	16.7	11.1	0.8	3.3
Taxes other than income taxes	—	—	—	—	1.4	4.3
Other	(0.3)	—	—	—	—	0.0
Interest expense, net	22.0	—	—	—	—	—
Interest expense, allocated from Parent	19.4	88.0	21.2	6.1	—	—
Loss on debt extinguishment	—	—	3.7	—	—	—
Loss/(gain) on mark-to-market derivative contracts	30.2	(16.8)	12.0	(1.3)	—	—
Deferred income tax expense(1)	1.5	2.9	—	—	2.6	6.1
Net income	40.3	$ 11.6	$ 9.7	$ 16.1	$ 4.0	$ 9.5
Less:						
Net income attributable to predecessor operations	12.2					
Net income allocable to partners	28.1					
General partner interest in net income	0.6					
Net income available to common and subordinated unitholders	$ 27.5					
Net income per limited partner unit — basic	$ 0.81					
Net income per limited partner unit — diluted	$ 0.81					
Cash distributions declared per unit	$ 1.24					
Financial and Operating Data:						
Financial data:						
Operating margin(2)	$ 203.8	$ 171.7	$ 86.4	$ 42.4	$ 12.6	$ 36.1
Adjusted EBITDA(3)	$ 185.8	$ 154.1	$ 66.0	$ 31.3	$ 11.8	$ 32.8

	Years Ended December 31, 2007	Years Ended December 31, 2006	Years Ended December 31, 2005	March 12 (Inception) through December 31, 2004	SAOU/LOU Systems Predecessor 106-Day Period Period Ended April 15, 2004	SAOU/LOU Systems Predecessor Year Ended December 31, 2003
	(in millions of dollars, except operating and price data)					
Operating data:						
Gathering throughput, MMcf/d(4)	452.0	433.8	302.4			
Plant natural gas inlet, MMcf/d(5)	429.2	419.6	253.6			
Gross NGL production, MBbl/d	42.6	42.4	23.5			
Natural gas sales, BBtu/d	410.2	489.4	259.3			
NGL sales, MBbl/d	36.4	36.0	22.0			
Condensate sales, MBbl/d	3.6	3.3	1.3			
Average Realized Prices:(6)						
Natural Gas, $/MMBtu	$ 6.66	$ 6.68	$ 9.36			
NGL, $/gal	1.03	0.85	0.77			
Condensate, $/Bbl	65.62	59.87	58.96			
Balance sheet Data (at period end):						
Property plant and equipment, net	$ 1,259.6	$ 1,288.6	$ 1,325.9	$ 237.6	$ 266.0	$ 268.8
Total Assets	1,480.0	1,416.4	1,500.0	323.4	288.8	316.8
Long-term allocated debt (including current portion)	—	1,047.3	1,053.3	103.0	—	—
Long-term debt (including current portion)	626.3	—	—	—	—	—
Partners' capital/Net parent equity	614.2	245.9	281.2	139.2	170.9	177.3
Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 265.7	$ 124.4	$ 10.5	$ 28.2	$ 11.5	$ (6.3)
Investing activities	(40.7)	(32.9)	(6.8)	(2.9)	(1.2)	(2.4)
Financing activities	(174.0)	(91.5)	(3.7)	(25.4)	(10.3)	8.8

(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. Please see Non-GAAP Financial Measures — Operating Margin, included in this Item 6.

(3) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization and non-cash income or loss related to derivative instruments. Please see Non-GAAP Financial Measures — Adjusted EBITDA, included in this Item 6.

(4) 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.

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

(6) 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 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.

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.

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	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005	March 12 (Inception) through December 31, 2004	SAOU/LOU Systems Predecessor: 106 Day Period Ended April 15, 2004	SAOU/LOU Systems Predecessor: Year Ended December 31, 2003
	(in millions)					
Reconciliation of “Adjusted EBITDA” to net cash provided by operating activities:						
Net cash provided by (used in) operating activities	$ 270.5	$ 124.4	$ 10.5	$ 28.2	11.5	$ (6.3)
Allocated interest expense from parent(1)	18.5	81.8	16.5	5.2	—	—
Interest expense, net(1)	21.1	—	—	—	—	—
Changes in operating working capital which used (provided) cash:						
Accounts receivable	(89.8)	(78.5)	61.8	76.7	(23.7)	30.3
Accounts payable	(1.9)	13.7	(11.4)	(3.1)	21.3	(1.5)
Accrued liabilities	(33.5)	15.4	(13.3)	(76.5)	0.1	(0.2)
Other, including changes in noncurrent assets and liabilities	(29.3)	14.1	(10.1)	2.1	2.6	10.5
Noncash mark-to-market loss (gain)	30.2	(16.8)	12.0	(1.3)	—	—
Adjusted EBITDA	$ 185.8	$ 154.1	$ 66.0	$ 31.3	$ 11.8	$ 32.8
Reconciliation of “Adjusted EBITDA” to net income:						
Net income	$ 40.3	$ 11.6	$ 9.7	$ 16.1	$ 4.0	$ 9.5
Add:						
Allocated interest expense, net	19.4	88.0	21.2	6.1	—	—
Interest expense, net	22.0	—	—	—	—	—
Deferred income tax expense	1.5	2.9	—	—	2.6	6.1
Taxes other than income taxes	—	—	—	—	1.4	4.3
Depreciation and amortization expense	71.8	69.9	23.1	10.4	3.8	12.9
Risk Management Activities	0.6	(1.5)	—	—	—	—
Noncash mark-to-market loss (gain)	30.2	(16.8)	12.0	(1.3)	—	—
Adjusted EBITDA	$ 185.8	$ 154.1	$ 66.0	$ 31.3	$ 11.8	$ 32.8
Reconciliation of “operating margin” to net income:						
Net income	$ 40.3	$ 11.6	$ 9.7	$ 16.1	$ 4.0	$ 9.5
Add:						
Depreciation and amortization expense	71.8	69.9	23.1	10.4	3.8	12.9
Deferred income tax expense	1.5	2.9	—	—	2.6	6.1
Allocated interest expense, net	19.4	88.0	21.2	6.1	—	—
Interest expense, net	22.0	—	—	—	—	—
Loss on extinguishment of debt	—	—	3.7	—	—	—
Loss/(gain) on mark-to-market derivative contracts	30.2	(16.8)	12.0	(1.3)	—	—
General and administrative expense	18.9	16.1	16.7	11.1	0.8	3.3
Taxes other than income taxes	—	—	—	—	1.4	4.3
Gain on sale of assets	(0.3)	—	—	—	—	—
Operating margin	$ 203.8	$ 171.7	$ 86.4	$ 42.4	$ 12.6	$ 36.1

(1) Net of amortization of debt issuance costs of $1.8 million for the year ended December 31, 2007, $6.2 million for the year ended December 31, 2006 and $4.7 million for the year ended December 31, 2005.

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

On February 14, 2007, we had Targa's ownership interests in the North Texas System contributed 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).

Although 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, as all of the North Texas System's equity accounts were also carried forward intact initially, and subsequently adjusted due to the cash consideration we paid for the acquired net assets.

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 consolidated financial statements and all other financial information included in this report have been restated to assume that the transfer of the North Texas System net assets from Targa to us had occurred at the date when both the North Texas System and the SAOU and LOU Systems met the accounting requirements for entities under common control (October 31, 2005). As a result, financial statements and financial information presented for prior periods in this report have been restated.

Accordingly, our historical results include the historical results of the SAOU and LOU Systems (acquired by Targa effective April 16, 2004) for the years ended December 31, 2007, 2006 and 2005; 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 and transport through our pipeline systems, 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.

Our processing contract arrangements can have a significant impact on our profitability. We process natural gas under a combination of percent-of-proceeds contracts (approximately 79% of our gathered natural gas volumes), wellhead purchases/keep-whole contracts (approximately 19% of our gathered natural gas volumes), fee-based contracts (approximately 1% of our gathered natural gas volumes) and hybrid contracts (approximately 1% of our gathered natural gas volumes). The percent-of-proceeds and keep-whole contracts expose us to commodity price risk. We attempt to mitigate this risk through hedging activities which can materially impact our results of operations. Please see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk”.

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. For a more complete discussion of the types of contracts under which we process natural gas, please see “Item 1. Business — Market Overview”.

The historical financial statements of the SAOU and LOU Systems and the North Texas System include certain items that will not materially impact our future results of operations and liquidity and do not fully reflect a number of other items that will materially impact 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 the Dynegy Inc.’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 $868.9 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.

On November 20, 2007, the Underwriters exercised their option to purchase an additional 1,800,000 common units. The gross proceeds from the Underwriters exercise of their option to purchase additional common units were $48.4 million (approximately $46.5 million after underwriting discounts). The proceeds from the exercise of the underwriters' option were used to reduce outstanding borrowings under our credit facility.

Concurrent with the acquisition of the SAOU and LOU Systems, we entered into a Commitment Increase Supplement (the "Supplement") to our existing five-year $500 million senior secured revolving credit facility. The Supplement increased the aggregate commitment under our credit agreement by $250 million to an aggregate of $750 million. 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 our credit agreement, as supplemented and amended, of up to $1 billion.

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 2008 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, please 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 are capped at $5.0 million per year for three years, subject to adjustment. 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 of approximately $3.1 million for the year ended December 31, 2007, including one-time expenses associated with our equity offerings, financing arrangements and acquisitions, are 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, incremental 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.

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

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

ii. 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 Amended and Restated Omnibus Agreement and (b) fully allocated as to the SAOU and LOU Systems according to Targa's previously established allocation practices;

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

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

Allocated general and administrative expenses were $13.9 million, $16.1 million and $16.7 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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). On January 24, 2008, a cash distribution of $0.3975 per common unit ($1.59 per common unit on an annualized basis) was declared for the fourth quarter of 2007. 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 unit was paid. The following table shows the timing and payments of our distributions:

Quarter Ended	Distribution per Common Unit	Distribution per Subordinated Unit	Declared	Paid
December 31, 2007	$ 0.3975	$ 0.3975	January 24, 2008	February 14, 2008
September 30, 2007	0.3375	0.3375	October 23, 2007	November 14, 2007
June 30, 2007	0.3375	0.3375	July 23. 2007	August 14, 2007
February 14, 2007 to March 31, 2007	0.16875	0.16875	April 23, 2007	May 15, 2007

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. In 2007, the prices we realized for natural gas decreased to an average of $6.58 per MMBtu from an average of $6.66 per MMBtu for 2006. For 2006, the prices we realized for natural gas declined to an average of $6.66 per MMBtu from an average of $9.36 per MMBtu for 2005. We believe that current natural gas prices will continue to cause relatively high levels of natural gas-related drilling in our systems as producers seek to increase their level of natural gas production.

Commodity Prices. Our operating income generally improves in an environment of higher natural gas and NGL prices, primarily as a result of our percent-of-proceeds contracts. For 2007, excluding the impact of hedging activities, we sold an average of 410.2 BBtu/d of residue gas at an average price of $6.58 per MMBtu, as compared to 489.4 BBtu/d at an average price of $6.66 per MMBtu for 2006, and 259.3 BBtu/d at an average price of $9.36 per MMBtu for 2005. For 2007, we sold an average of 36.4 MBbl/d of NGLs at an average price of $44.10 per Bbl, as compared to 36.0 MBbl/d at an average price of $36.12 per Bbl for 2006, and 22.0 MBbl/d at an average price of $33.18 per Bbl for 2005. 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. 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, please see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk”.

Rising Operating Costs. The current high levels of natural gas exploration, development and production activities are increasing competition for personnel and equipment. This increased competition is placing upward pressure on the prices we pay for labor, supplies, property, plant and equipment. We attempt to recover increased costs from our customers. To the extent we are unable to procure necessary supplies or to recover higher costs, our operating results will be negatively impacted.

Our Operations

Our results of operations are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, transported 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, transport 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 index prices based on 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. For the year ended December 31, 2007, our percent-of-proceeds activities accounted for approximately 79% 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 all 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. For a more complete description of these arrangements, please see “Item 13. Certain Relationships and Related Transactions and Director Independence” and “Item 1. Business — Market Access”.

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, facility efficiencies and fuel consumption, (2) operating margin, (3) operating expenses, (4) general and administrative 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 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.

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.

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, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(in millions)	
Reconciliation of "Adjusted EBITDA" to net cash provided by operating activities:			
Net cash provided by (used in) operating activities	$ 270.5	$ 124.4	$ 10.5
Allocated interest expense from parent(1)	18.5	81.8	16.5
Interest expense, net(1)	21.1	—	—
Changes in operating working capital which used (provided) cash:			
Accounts receivable	(89.8)	(78.5)	61.8
Accounts payable	(1.9)	13.7	(11.4)
Accrued liabilities	(33.5)	15.4	(13.3)
Other, including changes in noncurrent assets and liabilities	(29.3)	14.1	(10.1)
Noncash mark-to-market loss (gain)	30.2	(16.8)	12.0
Adjusted EBITDA	$ 185.8	$ 154.1	$ 66.0
Reconciliation of "Adjusted EBITDA" to net income:			
Net income	$ 40.3	$ 11.6	$ 9.7
Add:			
Allocated interest expense, net	19.4	88.0	21.2
Interest expense, net	22.0	—	—
Deferred income tax expense	1.5	2.9	—
Taxes other than income taxes	—	—	—
Depreciation and amortization expense	71.8	69.9	23.1
Risk Management Activities	0.6	(1.5)	—
Noncash mark-to-market loss (gain)	30.2	(16.8)	12.0
Adjusted EBITDA	$ 185.8	$ 154.1	$ 66.0
Reconciliation of "operating margin" to net income:			
Net income	$ 40.3	$ 11.6	$ 9.7
Add:			
Depreciation and amortization expense	71.8	69.9	23.1
Deferred income tax expense	1.5	2.9	—
Allocated interest expense, net	19.4	88.0	21.2
Interest expense, net	22.0	—	—
Loss on extinguishment of debt	—	—	3.7
Loss/(gain) on mark-to-market derivative contracts	30.2	(16.8)	12.0
General and administrative expense	18.9	16.1	16.7
Taxes other than income taxes	—	—	—
Gain on sale of assets	(0.3)	—	—
Operating margin	$ 203.8	$ 171.7	$ 86.4

(1) Net of amortization of debt issuance costs of $1.8 million for the year ended December 31, 2007, $6.2 million for the year ended December 31, 2006 and $4.7 million for the year ended December 31, 2005.

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, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005(a)
		(in millions)	
Net income (loss)	$ 40.3	$ 11.6	$ 9.7
Depreciation and amortization expense	71.8	69.9	23.1
Deferred income tax expense	1.5	2.9	—
Amortization of debt issue costs	1.8	6.2	4.7
Loss/(gain) on mark-to-market derivative contracts	30.2	(16.8)	12.0
Maintenance capital expenditures	(21.5)	(16.3)	(6.2)
Distributable cash flow(b)	$ 124.1	$ 57.5	$ 43.3

(a) Includes two months of operations from North Texas System.

(b) Distributable cash flow for the years ended December 31, 2007, 2006 and 2005 reflects allocated interest from parent of $19.4 million $88.0 million and $21.2 million, respectively.

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 Three Months Ended December 31, 2007			For The Year Ended December 31, 2007			
		Pre-Acquisition			Pre-Acquisition		
	TRP LP	SAOU/LOU Oct 1, 2007 to Oct 23, 2007	Post Acquisition TRP LP	TRP LP	North Texas Jan 1, 2007 to Feb 13, 2007	SAOU/LOU Jan 1, 2007 to Oct 23, 2007	Post Acquisition TRP LP
Net income (loss)	$ 22.7	$ 4.7	$ 18.0	$ 40.3	$ (6.9)	$ 19.1	$ 28.1
Depreciation and amortization expense	18.1	0.9	17.2	71.8	6.9	11.7	53.2
Deferred income tax expense	0.4	(0.1)	0.5	1.5	—	—	1.5
Amortization of debt issue costs	0.4	—	0.4	1.8	—	0.9	0.9
Loss/(gain) on mark-to-market derivative contracts	1.9	1.9	—	30.2	—	30.2	—
Maintenance capital expenditures	(6.8)	(0.4)	(6.4)	(21.5)	(1.5)	(5.9)	(14.1)
Distributable Cash Flow	$ 36.7	$ 7.0	$ 29.7	$ 124.1	$ (1.5)	$ 56.0	$ 69.6

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Contract Mix

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, please see "Item 1. Business — Midstream Sector Overview" for a more detailed discussion of the contractual arrangements under which we operate. Set forth below is a table summarizing our average contract mix for the year ended December 31, 2007, including the potential impacts of changes in commodity prices on operating margins:

Contract Type	Percent of Throughput	Impact of Commodity Prices
Percent-of-Proceeds	79%	Decreases in natural gas and/or NGL prices generate decreases in operating margin.
Wellhead Purchases /Keep Whole	19%	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-liquids (or wellhead purchases/keep-whole in some circumstances, if economically advantageous to the processor). In per
Fee Based	1%	No direct impact from commodity price movements.

At times, producer preferences, competitive forces and other factors cause us to enter into more commodity price sensitive contracts, such as wellhead purchases and keep-whole arrangements. We prefer to enter into contracts with less commodity price sensitivity, including fee-based and percent-of-proceeds arrangements.

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. The Partnership's 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.

The Partnership recognizes 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, the Partnership receives 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 the

Partnership receives for services or purchases for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee-based contracts, the Partnership receives a fee based on throughput volumes.

The Partnership generally reports revenues gross in the consolidated statements of operations, in accordance with EITF 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Except for fee-based contracts, the Partnership acts as the principal in the transactions where we receive commodities, takes title to the natural gas and NGLs, and incurs 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 the Partnership's functional asset groups are as follows:

Asset Group	Range of Years
Natural gas gathering systems and processing facilities	15 to 25
Office and miscellaneous 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, 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.

In accordance with SFAS 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets,"* 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). The Partnership accounts for derivative instruments in accordance with SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended. Under SFAS 133, 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.

The Partnership's policy is to formally document all relationships between hedging instruments and hedged items, as well as its 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, the Partnership assesses 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.

Asset Retirement Obligations. Under the provisions of SFAS 143, *"Accounting for Asset Retirement Obligations,"* we record legal obligations to retire tangible, long-lived assets on our balance sheet as liabilities, recorded at a discount, when such liabilities are incurred. We have recorded approximately $3.3 million in asset retirement obligations as of December 31, 2007.

In March 2005, the FASB issued FASB Interpretation ("FIN") 47, *"Accounting for Conditional Asset Retirement Obligations."* This Interpretation clarifies the definition and treatment of conditional asset retirement obligations as discussed in SFAS 143. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the company. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. This Interpretation is intended to provide more information about long-lived assets, more information about potential future cash outflows for these obligations and more consistent recognition of these liabilities. Our adoption of FIN 47 on December 31, 2005 had no effect on our financial position, results of operations, or cash flows.

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.

Recent Accounting Announcements

For a discussion of recent accounting pronouncements that will affect us, see Note 3 to our Consolidated Financial Statements.

Results of Operations

Our results of operations for the years ended December 31, 2007 and 2006 are presented and evaluated on a combined basis, combining the results of operations reflected in the audited historical financial statements of the SAOU and LOU Systems with the operations of the North Texas System. The Predecessor Business for the year ended December 31, 2005 combines the results of operations for the SAOU and LOU Systems for the year then ended and the results of operations reflected in the audited historical financial statements of the North Texas System for the two-months after the DMS Acquisition.

The following table and discussion is a summary of our combined results of operations for the three years ended December 31, 2007.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
	(in millions of dollars, except operating and price data)		
Revenues	$ 1,661.5	$ 1,738.5	$ 1,172.5
Product purchases	1,406.8	1,517.7	1,061.7
Operating expense	50.9	49.1	24.4
Depreciation and amortization expense	71.8	69.9	23.1
General and administrative expense	18.9	16.1	16.7
Gain on sale of assets	(0.3)	—	—
Income from operations	113.4	85.7	46.6
Interest expense, net	22.0	—	—
Interest expense, allocated from Parent	19.4	88.0	21.2
Loss on extinguishment of debt	—	—	3.7
Loss/(gain) on mark-to-market derivative contracts	30.2	(16.8)	12.0
Deferred income tax expense(1)	1.5	2.9	—
Net income	$ 40.3	$ 11.6	$ 9.7
Financial data:			
Operating margin(2)	$ 203.8	$ 171.7	$ 86.4
Adjusted EBITDA(3)	$ 185.8	$ 154.1	$ 66.0
Operating data:			
Gathering throughput, MMcf/d(4)	452.0	433.8	302.4
Plant natural gas inlet, MMcf/d(5)(6)	429.2	419.6	253.6
Gross NGL production, MBbl/d	42.6	42.4	23.5
Natural gas sales, BBtu/d(6)	410.2	489.4	259.3
NGL sales, MBbl/d	36.4	36.0	22.0
Condensate sales, MBbl/d	3.6	3.3	1.3
Average realized prices:			
Natural Gas, $/MMBtu			
Average realized sales price	$ 6.58	$ 6.66	$ 9.36
Impact of hedging	0.08	0.02	—
Average realized price	$ 6.66	$ 6.68	$ 9.36
NGL, $/gal			
Average realized sales price	$ 1.05	$ 0.86	$ 0.79
Impact of hedging	(0.02)	(0.01)	(0.02)
Average realized price	$ 1.03	$ 0.85	$ 0.77
Condensate, $/Bbl			
Average realized sales price	$ 65.43	$ 59.28	$ 58.96
Impact of hedging	0.19	0.59	—
Average realized price	$ 65.62	$ 59.87	$ 58.96

(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. Please see "Non-GAAP Financial Measures — Operating Margin" included in this Item 7.

(3) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization and non-cash income or loss related to derivative instruments. Please see "Non-GAAP Financial Measures — Adjusted EBITDA", included in this Item 7.

(4) 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.

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

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

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

Total Operating Revenues. Revenues decreased by $77.0 million, or 4.4%, to $1,661.5 million (including $1.0 million in losses related to net hedge settlements) for 2007 compared to $1,738.5 million (including $0.9 million in losses related to net hedge settlements) for 2006. This decrease was primarily due to the following factors:

- a net increase attributable to prices of $104.0 million, consisting of a decrease in natural gas revenues of $2.4 million and increases in NGLs and condensate revenues of $99.0 million and $7.4 million, respectively;
- a net decrease attributable to volumes of $182.5 million, consisting of a decrease in natural gas revenues of $193.0 million and increases of NGLs and condensate revenues of $5.7 million and $4.8 million, respectively; and
- an increase in fee and other revenues of $1.5 million.

Average realized prices (net of the impact of hedging) for our sales of:

- natural gas decreased by $0.02 per MMBtu ($0.06 net increase per MMBtu due to hedging) or less than 1%, to $6.66 per MMBtu during 2007 compared to $6.68 per MMBtu for 2006.
- NGLs increased by $0.18 per gallon ($0.01 net decrease per gallon due to hedging), or 21%, to $1.03 per gallon for 2007 compared to $0.85 per gallon for 2006.
- condensate increased by $5.75 per Bbl ($0.40 net increase per Bbl due to hedging), 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. This 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 production 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 increases were 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, which decreased by $110.9 million, or 7%, compared to $1,517.7 million during 2006.

Operating Expenses. Operating expenses during 2007 were $50.9 million, which increased by $1.8 million, or 4%, compared to $49.1 million during 2006. The increase over 2006 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. Depreciation and amortization expense for 2007 was $71.8 million compared to $69.9 million for 2006, for 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. 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. Please see “Liquidity and Capital Resources” included in this Item 7 regarding our outstanding debt obligations.

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

Total Operating Revenues. Revenues increased by $566.1 million, or 48%, to $1,738.5 million (including $0.9 million in losses related to net hedge settlements) during 2006 compared to $1,172.5 million (including $7.9 million in losses related to net hedge settlements) for 2005. This increase was primarily due to the following factors:

- During 2006, we recorded a full year of production volume for the SAOU, LOU and North Texas Systems versus a full year of production volume for the SAOU and LOU Systems and only two months of production volume for the North Texas System in 2005;
- a net decrease attributable to prices of $432.8 million, consisting of a decrease to natural gas revenues of $478.8 million and increases to NGL and condensate revenues of $44.9 million and $1.1 million, respectively;
- a net increase attributable to volumes of $995.9 million, consisting of increases to natural gas, NGLs and condensate volumes of $786.0 million, $165.1 million and $44.8 million, respectively, and
- an increase in fee and other revenues of $2.9 million.

Average realized prices (net of the impact of hedging) for our sales of:

- natural gas decreased by $2.68 per MMBtu (including a $0.02 increase per MMBtu due to hedging), or 29%, to $6.68 per MMBtu during 2006 compared to $9.36 per MMBtu for 2005.
- NGLs increased by $0.08 per gallon (with a $0.01 increase per gallon due to hedging), or 11%, to $0.85 per gallon for 2006 compared to $0.77 per gallon for 2005.
- condensate increased by $0.91 per Bbl ($0.59 increase per Bbl due to hedging), or 2%, to $59.87 per Bbl for 2006 compared to $58.96 per Bbl for 2005.

Natural gas sales volumes increased by 230.1 BBtu/d, or 89%, to 489.4 BBtu/d during 2006 compared to 259.3 BBtu/d for 2005. This increase in sales of natural gas volumes was attributable to a full year of North Texas sales volumes in 2006 compared to two months of sales volumes following our acquisition of North Texas in 2005, a net increase in natural gas purchased from affiliates and wellhead supplies attributable to additional well connections which were partially offset by the natural decline of field production. The increase in condensate sales volumes was primarily due to the full year of production for the North Texas System in 2006 compared to only tow months of 2005. NGL sales volumes increased by 14.0 MBbl/d, or 64%, to

36.0 MBbl/d during 2006 compared to 22.0 MBbl/d for 2005. Condensate volumes increased by 2.0 MBbl/d, or 154%, to 3.3 MBbl/d during 2006 compared to 1.3 MBbl/d for 2005. The increases in both natural gas and condensate sales volumes were primarily due the full year of production for the North Texas System in 2006 compared to only two months of 2005.

Product Purchases. Product purchases increased by $456.0 million, or 43%, to $1,517.7 million for 2006 compared to $1,061.7 million for 2005.

Operating Expenses. Operating expenses increased by $24.7 million, or 101%, to $49.1 million for 2006 compared to $24.4 million for 2005. Again, the primary factor was the addition of a full year's operating expense for the North Texas System in 2006 versus two months in 2005.

Depreciation and Amortization. Depreciation and amortization expense increased by $46.8 million, or 203%, to $69.9 million for 2006 compared to $23.1 million for 2005. The increase is due primarily to the higher carrying value of property, plant and equipment of the North Texas System for a full year in 2006 versus two months in 2005.

General and Administrative. General and administrative expense decreased by $0.6 million, or 4%, to $16.1 million for 2006 compared to $16.7 million for 2005. The decrease was the result of lower allocated costs following the DMS Acquisition due to lower parent costs and to adjustments to the factors used to allocate general and administrative expense.

Interest Expense. Interest expense for 2006 was $88.0 million compared to $21.2 million for 2005. Interest expense recorded for 2006 reflects an allocation of debt and related interest expense incurred by Targa and allocated to the SAOU, LOU and North Texas Systems in connection with debt incurred associated with the acquisitions made by Targa. Interest expense for 2006 represents a full year of interest allocation related to the North Texas System that was acquired as part of the DMS acquisition in October 2005, whereas interest expense for 2005 represents two months of allocated interest.

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 or to meet our collateral requirements 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. Please see "Item 1A. Risk Factors."

Historically, our cash generated from operations has been sufficient to finance our operating expenditures and maintenance and expansion capital expenditures, with remaining amounts being distributed to Targa, during its period of ownership and to our unitholders since Targa's contribution of assets to us and our acquisition of assets from Targa. Our sources of liquidity include:

- cash generated from operations;
- borrowings under our credit facility;
- issuance of additional partnership units; and
- debt offerings.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure requirements and our minimum quarterly cash distributions for at least the next year.

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 us and Targa 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 does 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.

We had positive working capital of $15.9 million as of December 31, 2007, compared to negative working capital of $369.0 million as of December 31, 2006. Excluding the current portion of allocated debt that was retired by Targa with proceeds received from the IPO, our negative working capital balance at December 31, 2006 would have been $28.2 million. This increase in the amount of working capital is attributable to operations of the larger organization and cash generated from their operations.

Cash Flow. Net cash provided by or used in operating activities, investing activities and financing activities for the years ended December 31, 2007, 2006 and 2005 were as follows:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(in millions)	
Net cash provided by (used in):			
Operating activities	$ 270.5	$ 124.4	$ 10.5
Investing activities	(40.7)	(32.9)	(6.8)
Financing activities	(178.8)	(91.5)	(3.7)

Operating Activities. Net cash provided by operating activities increased by $146.1 million, or 117%, for the year ended December 31, 2007 compared to the year ended December 31, 2006. This increase is attributable to a increase in our net income, increased non-cash charges and increases in working capital balances. Net cash provided by operating activities increased by $113.9 million for the year ended December 31, 2006 compared to the year ended December 31, 2005. This increase is primarily attributable to the inclusion of a full year of operations for the North Texas System in 2006, compared to only two months for 2005, as the North Texas System was acquired as part of the DMS Acquisition in October 2005, and its net income, adjusted for non-cash charges, as presented in the combined statements of cash flows and changes in working capital was only included for the period subsequent to the acquisition.

Investing Activities. Net cash used in investing activities for the year ended December 31, 2007 increased $7.8 million, or 24%, compared to the year ended December 31, 2006, primarily due to the completion of gathering system expansion projects and higher major maintenance expenditures of $5.2 million primarily due to the increased size of our gathering systems and the effect of higher utilization of our field compression facilities.

Financing Activities. The net cash used in financing activities for the year ended December 31, 2007 increased by $87.3 million compared to the year ended December 31, 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 during 2008 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, reduce costs or enhance revenues.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(in millions)	
Capital expenditures:			
Expansion	$ 22.4	$ 16.0	$ 0.6
Maintenance	21.5	16.3	6.2
	$ 43.9	$ 32.3	$ 6.8

We estimate that our capital expenditures will be approximately $60 million in 2008. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that we will invest significant amounts of capital to grow and acquire assets. Expansion capital expenditures may vary significantly based on investment opportunities.

We expect to fund future capital expenditures with funds generated from our operations, borrowings under our credit facility, the issuance of additional partnership units and debt offerings.

Description of Credit Agreement. On February 14, 2007, we entered into a five-year $500 million senior secured revolving credit agreement (the “Credit Agreement”) and borrowed approximately $294.5 million. The proceeds from this borrowing, together with approximately $371.2 million of net proceeds from 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), were used to repay approximately $665.7 million of allocated indebtedness.

Concurrent with the acquisition of the SAOU and LOU Systems on October 24, 2007, we entered into a Commitment Increase Supplement (the “Supplement”) to the Credit Agreement. The Supplement increased the aggregate commitments under the Credit Agreement by $250 million to an aggregate of $750 million. We paid for our acquisition of the SAOU and LOU Systems with the proceeds from our offering of common units and borrowings under the increased Credit Agreement.

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 (the “Amended Credit Agreement”), up to $1 billion.

The Amended 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 Amended Credit Agreement) exists. The Amended 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 5.00 to 1.00, subject to certain adjustments. The Amended 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 Amended 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 Amended Credit Agreement contains various covenants that may limit, among other things, our ability to:

- incur indebtedness;
- grant liens; and
- engage in transactions with affiliates.

Any subsequent replacement of our Amended Credit Agreement or any new indebtedness could have similar or greater restrictions.

In December 2007, we entered into interest rate swaps with a notional amount of $200 million. At December 31, 2007, we had the following open interest rate swaps:

Effective Date	Expiration Date	Notional Amount	Index	Fixed Rate
12/13/2007	1/24/2011	$ 50,000,000	3 Month USD LIBOR	4.0775%
12/18/2007	1/24/2011	$ 50,000,000	3 Month USD LIBOR	4.2100%
12/21/2007	1/24/2012	$ 50,000,000	3 Month USD LIBOR	4.0750%
12/21/2007	1/24/2012	$ 50,000,000	3 Month USD LIBOR	4.0750%

Each of these interest rate swaps have been designated as cash flow hedges of variable rate interest payments on a notional amount of $50 million in borrowings under our Amended Credit Agreement.

Contractual Obligations. Following is a summary of our contractual cash obligations over the next several fiscal years, as of December 31, 2007:

	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	$ 626.3	$ —	$ —	$ 626.3	$ —
Interest on debt obligations(1)	150.3	36.4	72.9	41.0	—
Operating lease obligations	0.1	0.1	—	—	—
Capacity payments(2)	16.8	9.2	6.8	0.8	—
Right of way	4.9	0.3	0.5	0.5	3.6
Asset retirement obligation	3.3	—	—	—	3.3
	$ 801.7	$ 46.0	$ 80.2	$ 668.6	$ 6.9

(1) Represents interest expense on partnership debt, based on interest rates as of December 31, 2007. We used an average rate of 5.8% to estimate our interest on variable rate debt obligations.

(2) Consists of capacity payments for natural gas pipelines.

Available Credit. As of March 11, 2008, we had approximately $110.2 million in capacity available under our Amended Credit Agreement, after giving effect to outstanding borrowings of $601.3 million and the issuance of $38.5 million of letters of credit.

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, 2007, we have hedged the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes for the years 2008 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 NGLs, 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.

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For the years ended December 31, 2007 and 2006, our operating revenues were decreased by net hedge settlements of $1.0 million and $0.9 million, respectively. During 2007 and 2006, we entered into hedging arrangements for a portion of our forecast of equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). At December 31, 2007, we had the following open commodity derivative positions:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per Day 2008	2009	2010	2011	2012	Fair Value (in thousands)
Natural Gas Purchases								
Swap	NY-HH	8.34	1,467	—	—	—	—	$ (341)
			1,467	—	—	—	—	(341)
Natural Gas Sales								
Swap	IF-HSC	8.09	2,328	—	—	—	—	513
Swap	IF-HSC	7.39	—	1,966	—	—	—	(551)
			2,328	1,966	—	—	—	(38)
Swap	IF-NGPL MC	8.43	6,964	—	—	—	—	4,475
Swap	IF-NGPL MC	8.02	—	6,256	—	—	—	1,110
Swap	IF-NGPL MC	7.43	—	—	5,685	—	—	(667)
Swap	IF-NGPL MC	7.34	—	—	—	2,750	—	(387)
Swap	IF-NGPL MC	7.18	—	—	—	—	2,750	(435)
			6,964	6,256	5,685	2,750	2,750	4,096
Swap	IF-Waha	8.20	7,389	—	—	—	—	3,000
Swap	IF-Waha	7.61	—	6,936	—	—	—	(618)
Swap	IF-Waha	7.38	—	—	5,709	—	—	(1,288)
Swap	IF-Waha	7.36	—	—	—	3,250	—	(709)
Swap	IF-Waha	7.18	—	—	—	—	3,250	(789)
			7,389	6,936	5,709	3,250	3,250	(404)
Total Swaps			16,681	15,158	11,394	6,000	6,000	3,654
Floor	IF-NGPL MC	6.55	1,000	—	—	—	—	218
Floor	IF-NGPL MC	6.55	—	850	—	—	—	171
			1,000	850	—	—	—	389
Floor	IF-Waha	6.85	670	—	—	—	—	140
Floor	IF-Waha	6.55	—	565	—	—	—	93
			670	565	—	—	—	233
Total Floors			1,670	1,415	—	—	—	622
Basis Swap Jan 2008 Rec IF-HH minus $0.01, pay GD-HH, 403,000 MMBtu								6
								$ 3,941

NGLs

Instrument Type	Index	Avg. Price $/gal	Barrels per Day 2008	2009	2010	2011	2012	Fair Value (in thousands)
NGL Sales								
Swap	OPIS-MB	1.02	7,127	—	—	—	—	$ (40,051)
Swap	OPIS-MB	0.96	—	6,248	—	—	—	(20,573)
Swap	OPIS-MB	0.91	—	—	4,809	—	—	(5,506)
Swap	OPIS-MB	0.92	—	—	—	3,400	—	(3,210)
Swap	OPIS-MB	0.92	—	—	—	—	2,700	(2,030)
			7,127	6,248	4,809	3,400	2,700	$ (71,370)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per Day 2008	2009	2010	2011	2012	Fair Value (in thousands)
Condensate Sales								
Swap	NY-WTI	70.68	384	—	—	—	—	$ (3,013)
Swap	NY-WTI	69.00	—	322	—	—	—	(2,008)
Swap	NY-WTI	68.10	—	—	301	—	—	(1,705)
Total Swaps			384	322	301	—	—	(6,726)
Floor	NY-WTI	60.50	55	—	—	—	—	2
Floor	NY-WTI	60.00	—	50	—	—	—	9
Total Floors			55	50	—	—	—	11
			439	372	301	—	—	$ (6,715)

Customer Hedges

Customer Hedges

Period	Commodity	Instrument Type	Daily Volume	Average Price	Index	Fair Value (in thousands)
Purchases						
Jan 2008 — June 2008	Natural gas	Swap	8,440 MMBtu	7.23 per MMBtu	NY-HH	$ 8
Sales						
Jan 2008 — June 2008	Natural gas	Fixed price sale	8,440 MMBtu	7.23 per MMBtu	NY-HH	(8)
						$ —

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 March 11, 2008, there were borrowings of approximately $601.3 million outstanding under our amended Credit Agreement.

Because of the interest rate risk on our credit facility we entered into four interest rate swaps as of December 31, 2007 to reduce this risk, as shown below:

Trade Date	Term	From	To	Rate	Notional Amount (in thousands)
12/11/07	3 years	12/13/07	1/24/11	4.0775%	$ 50,000
12/14/07	3 years	12/18/07	1/24/11	4.2100%	50,000
12/19/07	4 years	12/21/07	1/24/12	4.0750%	50,000
12/19/07	4 years	12/21/07	1/24/12	4.0750%	50,000

Each swap fixes the three month LIBOR rate, prior to credit margin, at the indicated rates for the specified amounts of related debt outstanding over the term of each swap agreement. 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 $4.3 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 that have terms of 15 years pursuant to which Targa purchases all of our natural gas, NGLs and high-pressure condensate. In addition, we are also party to an omnibus agreement with Targa which addresses, among other things, the provision of general and administrative and operating services to us. As of September 6, 2007, Moody's and Standard & Poor's assigned Targa corporate credit ratings of B1 and B, respectively, which are speculative ratings. A speculative rating signifies a higher risk that Targa will default on its obligations, including its obligations to us, than does an investment grade 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.

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 report.

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

None.

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

Disclosure Controls and Procedures

Our management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, our disclosure controls and procedures were effective to provide reasonable assurance that (i) all material information relating to us required to be included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) such information is accumulated and communicated to our management, including our Chief Executive Office and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining an adequate system of internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control system was designed to provide reasonable assurance to our management and board of directors of our general partner regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, internal control over financial reporting may not prevent or detect misstatements. 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 policies and procedures may deteriorate.

Our management, including our Chief Executive Officer and Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2007 based on the framework in "Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission." Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2007.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only management's report in this annual report.

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, our 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 initial 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. Please 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	60	Chief Executive Officer and Director
Joe Bob Perkins	47	President
James W. Whalen	66	President — Finance and Administration and Director
Roy E. Johnson	63	Executive Vice President
Michael A. Heim	59	Executive Vice President and Chief Operating Officer
Jeffrey J. McParland	53	Executive Vice President, and Chief Financial Officer
Paul W. Chung	48	Executive Vice President, General Counsel and Secretary
Peter R. Kagan	39	Director
Chansoo Joung	47	Director
Robert B. Evans	59	Director
Barry R. Pearl	58	Director
William D. Sullivan	51	Director

(1) As of March 1, 2008

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. Mr. Joyce has also served as a member of Targa's board of directors since February 2004. 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, 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, 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., Cambrien 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 31, 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 Energy, 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, 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% stockholders 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 2007, all of our directors and executive officers, other than Mr. Whalen, and beneficial owners of more than 10% of our common stock complied with

Section 16(a) filing requirements applicable to them. Mr. Whalen filed one late Form 4 with respect to a purchase of some of our common units.

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 and framework 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"). However, 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. As used in this Compensation Discussion and Analysis, references to "our," "we," "us" 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.

As a result of this philosophy, 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 at a general level to ensure that our total compensation is within a comparable range. 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. Senior Management and the TRII Compensation Committee, however, 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 2007, Senior Management identified peer companies that competed with us in the midstream natural gas industry and reviewed compensation information filed by the peer companies with the SEC. The peer group reviewed by Senior Management for 2007 consisted of the following companies: Atlas America, Copano Energy, Crosstex Energy, DCP Midstream, Enbridge Energy Partners, Energy Transfer Partners, Magellan Midstream, MarkWest Energy Partners, Martin Midstream, Oneok Partners, Plains All American Pipeline, Regency Energy Partners, TEPPCO Partners and Williams Energy Partners.

Senior Management intends to review 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 compensation consultants 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 considers this proposal (which he may request Senior Management to modify based on information available to him or that he requests of Senior Management) and his 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

The compensation philosophy for our executive officers centers on long-term equity awards to attract, motivate and retain our executive team. 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. 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. Within this 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 2007 Annual Incentive Plan (the "Bonus Plan") was adopted on January 23, 2007 to reward our employees for contributions towards our achievement of financial and operational goals 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, a discretionary cash bonus pool is expected to be funded annually based on our achievement of certain strategic, financial and operational objectives recommended by our CEO and approved by the TRII Compensation Committee. 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 the recommendation of their supervisors, managers and line officers.

For 2007, the TRII Compensation Committee aligned the cash bonus pool with the following six key business priorities: (i) involving employees in improving our businesses; (ii) proactively and aggressively investing in our businesses and developing the pipeline of projects and opportunities; (iii) bringing closure to hurricane repair and recovery; (iv) identifying and pursuing new opportunities in the downstream sector; (v) debt reduction and achievement of capital structure goals; and (vi) executing on all fronts (including the financial business plan). The Bonus Plan established goals that the TRII Compensation Committee will consider 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 connection with the initial public offering of the Partnership, Targa Investments issued to our named executive officers cash-settled performance unit awards linked to the performance of the Partnership's common units that will vest in August of 2010, 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.

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 employees 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 our common units, they own, directly and indirectly, approximately 3% of our 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

Base Salary. In 2007, base salaries for our named executive officers were generally lower than similar positions in our peer group.

Annual Cash Incentives. In January 2008, the TRII Compensation Committee approved a cash bonus pool of 200% of the target level for the employee group, including our named executive officers, under the Bonus Plan for performance during 2007. The executive officers received bonus awards equivalent to the same percentage of target as the Company bonus pool. The TRII Compensation Committee paid maximum level bonuses under the Bonus Plan in recognition of outstanding organizational performance in 2007. Our named executive officers received cash bonuses under the Bonus Plan based on our achievement of overall goals in 2007 as follows:

Rene R. Joyce	$	300,000
Jeffrey J. McParland	$	235,000
Joe Bob Perkins	$	270,000
James W. Whalen	$	270,000
Michael A. Heim	$	250,000

Equity/Stock Option Exchange. In May 2007, options relating to Targa Investments' preferred stock held by the employees, including the named executive officers, were exchanged for (i) a grant of 10 shares of Targa Investments common stock for each option and (ii) a right to receive a cash payment in the amount of $27.69 for each option. Except for the grant of shares in the stock option exchange, the TRII Compensation Committee did not award additional equity to our named executive officers.

Long-term Cash Incentives. In connection with the Partnership's initial public offering in February 2007, Targa Investments issued to key employees and the 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 August of 2010, 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 2007 were: Energy Transfer Partners, Oneok Partners, Copano Energy, DCP Midstream, Regency Energy Partners, Plains All American Pipeline, MarkWest Energy Partners, Williams Energy Partners, Magellan Midstream, Martin Midstream, Enbridge Energy Partners, Crosstex Energy 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 February 2007, our named executive officers, who are also executive officers of the General Partner, received an initial award of performance units as follows: 15,000 performance units to Mr. Joyce, 8,200 performance units to Mr. McParland, 10,800 performance units to Mr. Perkins, 10,800 performance units to Mr. Whalen and 10,000 performance units to Mr. Heim.

Retirement Benefits. For 2007, the discretionary amount contributed to the 401(k) Plan equaled 2.25% of the employee's eligible compensation.

Health and Welfare Benefits. For 2007, our named executive officers participated in our health and welfare benefit programs, including medical, health, life insurance, and 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 2007, other than parking subsidies.

Changes for 2008

Annual Cash Incentives. In connection with the development of our 2008 business plan and discussion of the plan with the Targa Investments Board, Senior Management proposed a set of strategic priorities. In January 2008, the TRII Compensation Committee approved the Targa Investments 2008 Annual Incentive Compensation Plan (the "2008 Bonus Plan"), the cash bonus plan for performance during 2008, and, with input from the Targa Investments Board, established 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 (iv) execute on all fronts (including the 2008 business plan and above priorities). 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 2008, 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: 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.

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, McParland, Whalen and Chung. Please see “Item 13. Certain Relationships and Related Transactions, and Director Independence” for a description of relationships requiring disclosure under the SEC’s rules for requiring disclosure 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, 2007 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 2007. 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 2007

	Year	Salary	Stock Awards ($)(1)	Option Awards ($)(1)	Non-Equity Incentive Plan Compensation	All Other Compensation(2)	Total Compensation
Rene R. Joyce	2007	$ 293,750	$ 459,769	$ 3,244	$ 300,000	$ 817,850	$ 1,874,613
Chief Executive Officer	2006	266,530	312,513	3,244	262,000	25,536	869,823
Jeffrey J. McParland	2007	230,000	316,770	3,244	235,000	674,179	1,459,193
Executive Vice President and Chief Financial Officer	2006	210,280	236,720	3,244	204,400	23,386	678,030
Joe Bob Perkins	2007	265,000	366,318	3,244	270,000	817,775	1,722,337
President	2006	244,030	260,294	3,244	238,000	23,474	769,042
James W. Whalen	2007	265,000	224,796	—	270,000	817,775	1,577,571
President — Finance and Administration	2006	244,030	227,546	—	238,000	17,539	727,115
Michael A. Heim	2007	243,750	366,318	3,244	250,000	817,725	1,681,037
Executive Vice President and Chief Operating Officer	2006	217,791	260,294	3,244	214,000	23,411	718,740

(1) The amounts reported in these columns reflect the aggregate dollar amounts recognized for stock awards (including performance units) and option awards, as applicable, for financial statement reporting purposes with respect to fiscal year 2007 (disregarding any estimate of forfeitures related to service-based vesting conditions). No stock awards or option awards granted to the named executive officers were forfeited during 2007. Detailed information about the amount recognized for specific awards is reported in the table under “Outstanding Equity Awards at 2007 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 each option granted since our adoption of SFAS 123R was estimated on the date of grant using the Black-Scholes option pricing model, which incorporates various assumptions for 2007 and 2006, including (i) expected term of the options of ten years, (ii) a risk-free interest rate of 4.6% and 4.5%, respectively, (iii) expected dividend yield of 0%, and (iv) expected stock price volatility on Targa Investments' common stock of 29.7% and 23.8%, respectively. 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 twelve months ended December 31, 2007 and the same period ended December 31, 2006 is $0.63 and $0.21 per share, respectively.

(2) For 2007 "All Other Compensation" includes the (i) payments under the Change of Control Bonus Plan and individual Bonus Agreements made in August 2007 in connection with the termination of the Change of Control Bonus Plan and the Bonus Agreements, (ii) aggregate value of matching, non-matching and discretionary contributions to our 401(k) plan and (iii) the dollar value of life insurance coverage.

Name	Change of Control Plan Termination	Change of Control Agreement Termination	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance	Total
Rene R. Joyce	$76,614	$717,537	$22,950	$749	$817,850
Jeffrey J. McParland	76,614	574,028	22,950	587	674,179
Joe Bob Perkins	76,614	717,537	22,950	674	817,775
James W. Whalen	76,614	717,537	22,950	674	817,775
Michael A. Heim	76,614	717,537	22,950	624	817,725

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 2007:

		Grants of Plan Based Awards for 2007							
		Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(1)			Estimated Future Payouts Under Equity Incentive Plan Awards(2)			All Other Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Stock and Option Awards
Name	Grant Date	Threshold	Target	2X Target	Threshold	Target (Units)	Maximum	(3)	(4)
Mr. Joyce	N/A	$ 75,000	$ 150,000	$ 300,000					447,450
	02/14/07					15,000			$ 0
	05/01/07							84,110	
Mr. McParland	N/A	58,750	117,500	235,000					
	02/14/07					8,200			244,606
	05/01/07							69,090	0
Mr. Perkins	N/A	67,500	135,000	270,000					
	02/14/07					10,800			322,164
	05/01/07							84,110	0
Mr. Whalen	N/A	67,500	135,000	270,000					
	02/14/07					10,800			322,164
	05/01/07							25,140	0
Mr. Heim	N/A	62,500	125,000	250,000					
	02/14/07					10,000			298,300
	05/01/07							84,100	0

(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) These awards were granted in exchange for options relating to Targa Investments' preferred stock held by the named executive officers.

(4) The dollar amounts shown are determined by multiplying the number of units reported in the table by $29.83 (the per unit fair value under FAS 123R 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 2007 salaries and bonuses 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 2007 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 2007 Fiscal Year-End" below.

Targa Investments 2004 Stock Incentive Plan

Stock Option Grants. No awards have been, or may be, made under the Targa Investments 2004 Stock Incentive Plan, as assumed and amended (the "2004 Incentive Plan"), from and after December 31, 2004. The 2004 Stock Incentive Plan governs options to purchase shares of Targa Investments' Series B Convertible Participating Preferred Stock ("Preferred Stock"). Subject to the terms of the applicable stock option agreement, options granted under the 2004 Incentive Plan have a vesting period of four years and remain exercisable for ten years from the date of grant. Additional details relating to previously granted stock options under the 2004 Incentive Plan are included in "— Outstanding Equity Awards at 2007 Fiscal Year-End" below. On May 1, 2007, employees and directors of Targa Investments surrendered all options to acquire shares of Preferred Stock in exchange for a cash payment of $27.69 and ten shares of restricted stock of Targa Investments for each option surrendered.

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Outstanding Equity Awards at 2007 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, 2007 for each of our named executive officers.

	Outstanding Equity Awards at 2007 Fiscal Year-End							
	Option Awards				Stock Awards			
Name	# Exercisable	# Unexercisable	Option Exercise Price	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested(11)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(12)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested(13)
Rene R. Joyce		21,772(1) 291,376(1) 246,549(1) 3,006(2) 2,559(2)	$ 0.75 $ 3.00 $ 15.00 $ 3.00 $ 15.00	10/31/2015 10/31/2015 10/31/2015 12/20/2015 12/20/2015	734,199(5) 7,116(6) 84,110(9)	$ 2,532,987 $ 24,550 $ 290,180	15,000	$ 444,300
Jeffrey J. McParland		21,772(1) 218,532(1) 184,912(1) 2,254(2) 1,919(2)	$ 0.75 $ 3.00 $ 15.00 $ 3.00 $ 15.00	10/31/2015 10/31/2015 10/31/2015 12/20/2015 12/20/2015	555,120(5) 5,337(6) 69,090(9)	$ 1,915,164 $ 18,413 $ 238,361	8,200	242,884
Joe Bob Perkins		21,772(1) 236,014(1) 199,705(1) 2,435(2) 2,073(2)	$ 0.75 $ 3.00 $ 15.00 $ 3.00 $ 15.00	10/31/2015 10/31/2015 10/31/2015 12/20/2015 12/20/2015	611,680(5) 5,764(6) 84,110(9)	$ 2,110,296 $ 19,886 $ 290,180	10,800	319,896
James W. Whalen	136,365 115,386 1,407 1,198	90,908(3) 76,922(3) 937(4) 798(4)	$ 3.00 $ 15.00 $ 3.00 $ 15.00	11/1/2015 11/1/2015 12/20/2015 12/20/2015	202,278(7) 2,220(8) 25,140(10)	$ 697,859 $ 7,659 $ 86,733	10,800	319,896
Michael A. Heim		21,772(1) 236,014(1) 199,705(1) 2,435(2) 2,073(2)	$ 0.75 $ 3.00 $ 15.00 $ 3.00 $ 15.00	10/31/2015 10/31/2015 10/31/2015 12/20/2015 12/20/2015	611,680(5) 5,764(6) 84,110(9)	$ 2,110,296 $ 19,886 $ 290,180	10,000	296,200

(1) Represents options to purchase shares of Targa Investments common stock awarded on October 31, 2005. These options vest on the following schedule: 70% vest on April 30, 2008, an additional 10% vest on October 31, 2008 and the remaining 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 the following schedule: 70% vest on June 20, 2008, an additional 10% vest on December 20, 2008 and the remaining 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 the following schedule: 50% vest on each of November 1, 2008 and 2009.

(4) Represents options to purchase shares of Targa Investments common stock awarded on December 20, 2005. These options vest on the following schedule: 50% vest on each of December 20, 2008 and 2009.

(5) Represents shares of restricted common stock of Targa Investments awarded on October 31, 2005. These shares vest on the following schedule: 70% on April 30, 2008; an additional 10% on October 31, 2008 and the remaining shares on October 31, 2009.

(6) Represents shares of restricted common stock of Targa Investments awarded on December 20, 2005. These shares vest on the following schedule: 70% on June 20, 2008; an additional 10% on December 20, 2008 and the remaining shares on December 20, 2009.

(7) Represents shares of restricted common stock of Targa Investments awarded on October 31, 2005 (2,721 shares) and November 1, 2005 (502,975 shares). These shares vest on the following schedule: 50% vest on each of October 31, 2008 and 2009 (with respect to the October 31, 2005 awards) and November 1, 2008 and 2009 (with respect to the November 1, 2005 awards).

(8) Represents shares of restricted common stock of Targa Investments awarded on December 20, 2005. These shares vest on the following schedule: 50% vest on each of December 20, 2008 and 2009.

(9) Represents shares of restricted common stock of Targa Investments awarded on May 1, 2007 in connection with the exchange of options relating to Targa Investments' preferred stock held by the named executive officers. These shares vest on the following schedule: 80% vest on January 1, 2008 and the remaining vest on April 16, 2008.

(10) Represents shares of restricted common stock of Targa Investments awarded on May 1, 2007 in connection with the exchange of options relating to Targa Investments' preferred stock held by the named executive officer. These shares vest on the following schedule: 80% vest on January 1, 2008 and the remaining vest on May 7, 2008.

(11) The dollar amounts shown are determined by multiplying the number of shares or units reported in the table by $3.45 (the value determined by an independent consultant pursuant to a valuation of Targa Investments' common stock as of October 24, 2007, which management believes is a reasonable approximation of the value of such stock as of December 31, 2007.

(12) Represents the number of performance units awarded on February 14, 2007 under the Targa Investments Long-Term Incentive Plan. These awards vest in August of 2010 based on the Partnership's performance over such 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."

(13) The dollar amounts shown are determined by multiplying the number of units reported in the table by $29.62 (the closing price of a common unit of the Partnership on December 31, 2007) and assume full payout under the awards at the time of vesting.

Option Exercises and Stock Vested in 2007

The following table provides the amount realized during 2007 by each named executive officer upon the exercise of options and upon the vesting of restricted common stock.

	Option Exercises and Stock Vested for 2007			
	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise(1)	Value Realized on Exercise(2)	Number of Shares Acquired on Vesting	Value Realized on Vesting(3)
Rene R. Joyce	84,110	$325,422		
Jeffrey J. McParland	69,090	$267,309		
Joe Bob Perkins	84,110	$325,422		
James W. Whalen	25,140	$ 97,267	102,249	$352,759
Michael A. Heim	84,110	$325,422		

(1) Represents shares of restricted common stock of Targa Investments awarded on May 1, 2007 in connection with the exchange of options relating to Targa Investments' preferred stock held by the named executive officers. At the time of exchange, the restricted common stock had a value of $1.10 per share. This value was determined by an independent consultant pursuant to a valuation of Targa Investments common stock as of December 31, 2006. The named executive officers received 10 shares of restricted common stock of Targa Investments for each option exchanged.

(2) This value includes a cash payment to the named executive officers of $27.69 per option exchanged.

(3) On October 31, 2007 and December 20, 2007, 101,139 and 1,110 shares, respectively, vested. The value realized on vesting used a per share price of $3.45. This value was determined by an independent consultant pursuant to a valuation of Targa Investments common stock as of October 24,

2007, which management believes is a reasonable approximation of the value of such stock as of December 31, 2007.

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 Investment's 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 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 (as defined below) 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, 2007.

Name	Change of Control	Termination for Death or Disability
Rene R. Joyce	$ 3,038,972(1)	$ 3,038,972(1)
Jeffrey J. McParland	2,330,074(2)	2,330,074(2)
Joe Bob Perkins	2,586,449(3)	2,586,449(3)
James W. Whalen	833,583(4)	833,583(4)
Michael A. Heim	2,586,449(5)	2,586,449(5)

(1) Of this amount, $2,532,987 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $24,549 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; $290,180 relates to the unvested shares of restricted stock of Targa Investments granted on May 1, 2007 in connection with the stock option exchange; $189,904 relates to the unvested options to purchase Targa Investments common stock granted on October 31, 2005; and $1,352 relates to the unvested options to purchase Targa Investments common stock granted on December 20, 2005.

(2) Of this amount, $1,915,164 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $18,412 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; $238,360 relates to the unvested shares of restricted stock of Targa Investments granted on May 1, 2007 in connection with the stock option exchange; $157,124 relates to the unvested options to purchase Targa Investments common stock granted on October 31, 2005; and $1,014 relates to the unvested options to purchase Targa Investments common stock granted on December 20, 2005.

(3) Of this amount, $2,110,296 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $19,886 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; $290,180 relates to the unvested shares of restricted stock of Targa Investments granted on May 1, 2007 in connection with the stock option exchange; $164,991 relates to the unvested options to purchase Targa Investments common stock granted on October 31, 2005; and $1,096 relates to the unvested options to purchase Targa Investments common stock granted on December 20, 2005.

(4) Of this amount, $3,754 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $694,106 relates to the unvested shares of restricted stock of Targa Investments granted on November 1, 2005; $7,660 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; $86,733 relates to the unvested shares of restricted stock of Targa Investments granted on May 1, 2007 in connection with the stock option exchange; $40,908 relates to the unvested options to purchase Targa Investments common stock granted on November 1, 2005; and $422 relates to the unvested options to purchase Targa Investments common stock granted on December 20, 2005.

(5) Of this amount, $2,110,296 relates to the unvested shares of restricted stock of Targa Investments granted on October 31, 2005; $19,886 relates to the unvested shares of restricted stock of Targa Investments granted on December 20, 2005; $290,180 relates to the unvested shares of restricted stock of Targa Investments granted on May 1, 2007 in connection with the stock option exchange; $164,991 relates to the unvested options to purchase Targa Investments common stock granted on October 31, 2005; and $1,096 relates to the unvested options to purchase Targa Investments common stock granted on December 20, 2005.

Other Agreements

In connection with the DMS acquisition on October 31, 2005, we entered into bonus agreements (the “Bonus Agreements”) with Messrs. Heim, Joyce, McParland, Perkins and Whalen and adopted the Targa

Resources, Inc. Bonus Plan (the "Change of Control Bonus Plan") applicable to eligible employees, including Messrs. Joyce, McParland, Perkins and Heim, that provided these named executive officers certain benefits upon a Change of Control. In addition, on July 12, 2006, in order to ensure managerial transition in the face of a potential transaction, the TRII Compensation Committee approved the Targa Investments Change of Control Executive Officer Severance Program (the "TRII Severance Program") in which all of our named executive officers were participants.

Bonus Agreements. Under the Bonus Agreements, following a Change of Control or a death or disability, our named executive officers were entitled to receive the following lump sum cash bonus amounts: Mr. Heim-$717,537; Mr. Joyce-$717,537; Mr. McParland-$574,028; Mr. Perkins-$717,537; and Mr. Whalen-$21,802.

Change of Control Bonus Plan. The Change of Control Bonus Plan provided a lump sum cash bonus payment in case there was a Change of Control or the plan was terminated. The bonus pool would have been $2 million if the weighted average sale price with respect to Targa Investments' preferred stock sold by Warburg Pincus between November 1, 2005 and the change of control was equal to or greater than $100 per share. The bonus pool would have been $0 if the weighted average sale price was equal to or less than $72.31 per share. The bonus pool would have been a prorated amount between $0 and $2 million if the weighted average sale price was between $72.31 and $100 per share.

TRII Severance Program. This program provided separation benefits to our executive officers who voluntarily terminated their employment or whose employment was terminated in connection with a change of control of Targa. In such event, executive officers would have received a lump sum cash payment, subsidized medical coverage for up to two years and minimal transition assistance. The lump sum cash payment would have been paid in an amount equal to (i) two multiplied by fifty percent of the executive officer's annual base pay in effect on the date immediately preceding the change of control, multiplied by (ii) a fraction, the numerator of which was the number of days during the period beginning on the first day of such fiscal year and ending on the date of such termination, and the denominator of which was three hundred sixty-five.

Termination of Change in Control and Termination Benefits

In connection with Targa Investment's entry into a credit facility in August 2007, which funded a distribution to Targa Investment's investors, the Targa Board elected to terminate the Bonus Agreements and the Change of Control Bonus Plan and to trigger the payments due under the agreements and plan. The TRII Severance Program was terminated without any payments to the named executive officers when the Targa Investments Board determined the need to ensure managerial transition in the case of a Change of Control was no longer necessary. As a result, no payments would have been made to the named executive officers under the Bonus Agreements, the Change of Control Bonus Plan and the TRII Severance Program if a change of control occurred or their employment was terminated in connection therewith as of December 31, 2007.

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2007:

	Fees Earned or Paid in Cash	Stock Awards ($)(1)	All Other Compensation(4)	Total Compensation
Robert B. Evans(2)(3)	$76,000	$22,250	$1,688	$ 99,938
Chansoo Joung(2)(3)	46,000	22,250	1,688	69,938
Peter R. Kagan(2)(3)	47,500	22,250	1,688	71,438
Barry R. Pearl(2)(3)	96,000	22,250	1,688	119,938
William D. Sullivan(2)(3)	74,500	22,250	1,688	98,438

(1) The amounts reported reflect the aggregate dollar amounts recognized for stock awards for financial statement reporting purposes with respect to fiscal year 2007 (disregarding any estimate of forfeitures related to service-based vesting conditions). No stock awards granted to the directors were forfeited

during 2007. For a discussion of the assumptions and methodologies used to value the awards reported in these columns, please see the discussion of stock awards contained in the Notes to Consolidated Financial Statements at Note 11 included in this annual report.

(2) Messrs. Evans, Joung, Kagan, Pearl and Sullivan each received 2,000 common units of the Partnership on February 14, 2007 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 $42,000, based on the initial public offering price of the common units. During 2007, Messrs. Joung and Kagan each received $1,690 in distributions on the common units of the Partnership that were awarded to them. The Partnership also recognized $22,500 of expense for each of the stock awards held by them.

(3) At December 31, 2007, Mr. Evans held 3,900 common units, Mr. Joung and Kagan each held 2,000 common units, Mr. Pearl held 4,300 common units and Mr. Sullivan held 6,700 common units of the Partnership.

(4) For 2007 "All Other Compensation" consists of the dividends paid on common units of the Partnership from unit awards.

Narrative to Director Compensation Table

In response to market developments identified by Apogee, a compensation consultant, the Board approved changes to director compensation for the 2007 fiscal year. For 2007, 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 Audit Committee and Conflicts Committee meeting attended. No additional fees are paid for attending board meetings. 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 February 2007 in connection with its initial public offering 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 2008

Director Long-term Equity Incentives. In March 2008, each of the General Partners' nonmanagement and independent directors received an award of 2,000 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.

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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 March 25, 2008 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 officers of Targa Resources GP LLC as a group.

	Targa Resources Partners LP					Targa Resources Investments Inc.			
Name of Beneficial Owner(1)	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	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%	24.96%	—	—	—	—
Lehman Brother Holdings Inc.(3)	2,619,219	7.56%	—	—	5.67%				
LaBranche Structured Products LLC(4)	2,510,920	7.25%	—	—	5.44%				
Rene R. Joyce	20,000	*	285,364	2.48%	*	56,208	1,217,212(7)	*	15.6%
Joe Bob Perkins	7,100	*	240,509	2.09%	*	47,632	1,021,798(8)	*	13.2%
Michael A. Heim	2,500	*	226,959	1.97%	*	39,192	1,021,798(9)	*	13.2%
Jeffrey J. McParland	1,500	*	201,663	1.75%	*	32,856	927,197(10)	*	12.1%
James W. Whalen	36,152	*	151,131	1.31%	*	14,978	790,742(11)	*	10.3%
Peter R. Kagan(5)	4,000	*	—	*	*	—	—	—	*
Chansoo Joung(5)	4,000	*	—	*	*	—	—	—	*
Robert B. Evans	5,900	*	—	*	*	—	—	—	*
Barry R. Pearl	6,300	*	—	*	*	—	—	—	*
William D. Sullivan	8,700	*	—	*	*	—	—	—	*
All directors and executive officers as a group (12 persons)	96,152	*	1,478,208	12.82%	3.41%	241,114	6,795,333	3.8%	71.5%

* 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 units 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 units directly 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, NY 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, N.Y. 10004.

(5) Warburg Pincus Private Equity VIII, L.P. (“WP VIII”) and Warburg Pincus Private Equity IX, L.P. (“WP IX”) in the aggregate beneficially own 73.6% of Targa Resources Investments Inc. The general partner of WP VIII is Warburg Pincus Partners, LLC (“WP Partners LLC”) and the general partner of WP IX is Warburg Pincus IX, LLC, of which WP Partners LLC is sole member. Warburg Pincus & Co. (“WP”) is the managing member of WP Partners LLC. WP VIII and WP IX are managed by Warburg Pincus LLC (“WP LLC”). The address of the Warburg Pincus entities is 466 Lexington Avenue, New York, New York 10017. Chansoo Joung and Peter R. Kagan, two of our directors, are each a general partner of WP and a Managing Director and Member of WP LLC.

Charles R. Kaye and Joseph P. Landy are each Managing General Partners of WP and Co-Presidents and Managing Members 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 presented as being beneficially owned by the directors and executive officers of Targa Resources GP LLC 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.

(7) Of this amount, 391,787 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(8) Of this amount, 320,244 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(9) Of this amount, 297,650 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(10) Of this amount, 254,356 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

(11) Of this amount, 52,213 shares of restricted common stock reflect options that are currently exercisable for shares of restricted common stock.

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 the formation of the Partnership and to be made to us by our general partner and its affiliates in connection with the ongoing operation and any liquidation of the Partnership. 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. Please 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, 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, 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. Both the North Texas System and the SAOU and LOU Systems have 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 SAOU and LOU Systems.

Indemnification Agreements. In February 2007, Targa Resources GP LLC, our general partner, and the Partnership 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 the Partnership or Targa Resources GP LLC is jointly liable in the proceeding with the Indemnitee, the Partnership 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 each of the Partnership 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 the Partnership 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.

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.

Item 14. ***Principal Accountant Fees and Services***

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we have paid PricewaterhouseCoopers for independent auditing, tax and related services for each of the last two fiscal years (dollars in thousands):

	For Year Ended December 31, 2007	For Year Ended December 31, 2006
Audit Fees(1)	$ 2,224.7	$ 820.7
Audit-Related Fees(2)	—	—
Tax Fees(3)	177.4	—
All Other Fees(4)	—	—

(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) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews. This category primarily includes services relating to internal control assessments and accounting-related consulting.

(3) 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.

(4) 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. No such services were rendered by PricewaterhouseCoopers during the last two years.

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 of our general partner has approved the use of PricewaterhouseCoopers as our independent principal accountant.

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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 this annual report. For a listing of these statements and accompanying footnotes, please see *"Index to Financial Statements"* on 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 financial 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/A 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	—	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)).
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 (incorporate 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	—	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)).
10.5	—	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)).
10.6	—	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)).
10.7+	—	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)).
10.8+	—	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)).
10.9+	—	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 February 13, 2007 (File No. 001-33303)).
10.10+	—	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 22, 2008 (File No. 001-33303)).
10.11	—	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)).
10.12	—	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)).
10.13	—	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)).
10.14	—	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)).
10.15	—	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)).
10.16	—	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)).

10.17	—	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)).
10.18	—	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)).
10.19+	—	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)).
10.20+	—	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)).
10.21+	—	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)).
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: March 31, 2008

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 March 31, 2008.

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

Report of Independent Registered Public Accounting Firm

To the Partners of Targa Resources Partners LP:

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, 2007 and 2006 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 7 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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 26, 2008

TARGA RESOURCES PARTNERS LP

CONSOLIDATED BALANCE SHEETS

	December 31, 2007	December 31, 2006
	(in thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 50,994	$ —
Receivables from third parties	59,346	61,559
Receivables from affiliated companies	87,547	—
Inventory	1,624	958
Assets from risk management activities	8,695	25,683
Other	269	—
Total current assets	208,475	88,200
Property, plant and equipment, at cost	1,433,955	1,391,644
Accumulated depreciation	(174,361)	(103,073)
Property, plant and equipment, net	1,259,594	1,288,571
Debt issue costs	6,588	—
Debt issue costs allocated from Parent	—	21,353
Long-term assets from risk management activities	3,040	15,851
Other long-term assets	2,275	2,396
Total assets	$ 1,479,972	$ 1,416,371
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 5,693	$ 3,773
Accrued liabilities	142,836	109,337
Current maturities of debt allocated from Parent	—	340,747
Liabilities from risk management activities	44,003	3,296
Total current liabilities	192,532	457,153
Long-term debt allocated from Parent	—	706,597
Long-term debt	626,300	—
Long-term liabilities from risk management activities	43,109	551
Other long-term liabilities	3,266	2,919
Deferred income tax liability	559	3,238
Commitments and contingencies (Note 11)		
Partners' capital:		
Common unitholders (34,636,000 units issued and outstanding at December 31, 2007)	770,207	—
Subordinated unitholders (11,528,231 units issued and outstanding at December 31, 2007)	(84,999)	—
General partner (942,128 units issued and outstanding at December, 2007)	4,234	—
Accumulated other comprehensive income (loss)	(75,236)	30,964
Net parent investment	—	214,949
Total partners' capital	614,206	245,913
Total liabilities and partners' capital	$ 1,479,972	$ 1,416,371

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(in thousands, except per unit amounts)	
Revenues from third parties	$ 630,773	$ 951,936	$ 1,110,911
Revenues from affiliates	1,030,696	786,589	61,539
Total operating revenues	1,661,469	1,738,525	1,172,450
Costs and expenses:			
Product purchases from third parties	1,215,733	1,194,751	1,041,686
Product purchases from affiliates	191,064	322,917	19,998
Operating expenses	50,931	49,075	24,394
Depreciation and amortization expense	71,756	69,957	23,069
General and administrative expense	18,927	16,063	16,721
Other	(296)	—	—
	1,548,115	1,652,763	1,125,868
Income from operations	113,354	85,762	46,582
Other expense:			
Interest expense, net	21,998	—	—
Interest expense allocated from Parent	19,436	88,025	21,177
Loss/(gain) on mark-to-market derivative contracts	30,221	(16,756)	11,973
Loss on debt extinguishment	—	—	3,701
Other	(30)	—	—
Income before income taxes	41,729	14,493	9,731
Deferred income tax expense	1,479	2,926	—
Net income	40,250	$ 11,567	$ 9,731
Less net income (loss) attributable to predecessor operations:			
For the period January 1, 2007 to February 13, 2007 for North Texas	(6,861)		
For the period January 1, 2007 to October 23, 2007 for SAOU/LOU	19,045		
Total	12,184		
Net income allocable to partners	28,066		
General partner interest in net income for the period	561		
Net income available to common and subordinated unitholders	$ 27,505		
Basic net income per common and subordinated unit	$ 0.81		
Diluted net income per common and subordinated unit	$ 0.81		
Basic average number of common and subordinated units outstanding	33,986		
Diluted average number of common and subordinated units outstanding	33,994		

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(in thousands)	
Net income	$ 40,250	$ 11,567	$ 9,731
Other comprehensive income (loss):			
Commodity hedges:			
Change in fair value of commodity hedges	(105,584)	36,937	(16,870)
Reclassification adjustment for settled periods	993	(822)	10,436
Related income taxes	312	(312)	—
Interest rate swaps:			
Change in fair value of interest rate swaps	(1,689)	1,267	(120)
Reclassification adjustment for settled periods	(232)	(488)	39
Other comprehensive income (loss)	(106,200)	36,582	(6,515)
Comprehensive income (loss)	$ (65,950)	$ 48,149	$ 3,216

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

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

	Net Parent Investment	Accumulated Other Comprehensive Income (Loss)	Partners' Capital: Limited Partners: Common	Partners' Capital: Limited Partners: Subordinated	Partners' Capital: General Partner	Total
	(in thousands)					
Balance at December 31, 2004	$ 138,326	$ 897	$ —	$ —	$ —	$ 139,223
Initial contribution — North Texas System	219,879	—	—	—	—	219,879
Distributions to Parent	(81,095)	—	—	—	—	(81,095)
Net income	9,731	—	—	—	—	9,731
Other comprehensive loss	—	(6,515)	—	—	—	(6,515)
Balance at December 31, 2005	286,841	(5,618)	—	—	—	281,223
Distributions to Parent	(83,459)	—	—	—	—	(83,459)
Net income	11,567	—	—	—	—	11,567
Other comprehensive income	—	36,582	—	—	—	36,582
Balance at December 31, 2006	214,949	30,964	—	—	—	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. to the Partnership	(396,905)	—	—	376,351	20,554	—
Book value of net assets transferred via common control from Targa Resources, Inc. to the Partnership	(245,181)	—	—	232,420	12,761	—
Distribution to Targa 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
Contribution of non-cash compensation	—	—	180	—	—	180
Other comprehensive loss	—	(106,200)	—	—	—	(106,200)
Distributions to unitholders	—	—	(20,871)	(9,726)	(624)	(31,221)
Balance at December 31, 2007	$ —	$ (75,236)	$ 770,207	$ (84,999)	$ 4,234	$ 614,206

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
		(in thousands)	
Cash flows from operating activities			
Net income	$ 40,250	$ 11,567	$ 9,731
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation	71,632	69,832	22,945
Accretion of asset retirement obligations	342	245	94
Amortization of intangibles	124	125	124
Amortization of debt issue costs	1,805	6,246	4,723
Noncash compensation	180	—	—
Gain on sale of assets	(296)	—	—
Deferred income tax expense	1,479	2,926	—
(Gain) loss on mark-to-market derivative contracts	30,221	(16,756)	11,973
Risk management activities	530	(1,541)	—
Changes in operating assets and liabilities:			
Accounts receivable	89,760	78,467	(61,826)
Inventory	(666)	1,373	(1,950)
Other	(273)	1,106	10
Accounts payable	1,920	(13,748)	11,439
Accrued liabilities	33,472	(15,408)	13,254
Net cash provided by operating activities	270,480	124,434	10,517
Cash flows from investing activities			
Purchases of property, plant and equipment	(41,088)	(32,575)	(7,197)
Other	372	(317)	422
Net cash used in investing activities	(40,716)	(32,892)	(6,775)
Cash flows from financing activities			
Proceeds from equity offerings	777,471	—	—
Costs incurred in connection with public offerings	(4,640)	—	—
Distributions to unit holders	(31,221)	—	—
Proceeds from borrowings under credit facility	721,300	—	—
Costs incurred in connection with financing arrangements	(7,491)	—	—
Repayments of loans:			
Affiliated	(665,692)	—	—
Credit facility	(95,000)	—	—
Distributions to Parent	(873,497)	(91,542)	(3,742)
Net cash used in financing activities	(178,770)	(91,542)	(3,742)
Net change in cash and cash equivalents	50,994	—	—
Cash and cash equivalents, beginning of period	—	—	—
Cash and cash equivalents, end of period	$ 50,994	$ —	$ —
Supplemental cash flow information:			
Interest paid	$ 15,453	$ —	$ —
Noncash investing and financing activities:			
Contribution of the North Texas System	—	—	219,879
Debt issue costs allocated from Parent	—	5,903	6,229
Long-term debt allocated from Parent			
Borrowing	—	—	(227,106)
Repayment	59,400	5,979	146,907
Net settlement of allocated indebtedness and debt issue costs	301,801	330	—
Net contribution of affiliated receivables	184,462	—	—

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization and Operations

Targa Resources Partners LP ("TRP LP") is a growth-oriented 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, Targa Resources Partners LP, together with its subsidiaries ("we," "us," "our" or the "Partnership") completed its 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 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 the 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 our 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

Our acquisition of the SAOU and LOU Systems from Targa has been accounted for as a transfer of assets between entities under common control in accordance with Statement of Financial Accounting Standards ("SFAS") 141, *"Business Combinations."* Targa's conveyance of the North Texas System to us in 2007 has also been accounted for as a transfer of assets between entities under common control. The SAOU and LOU Systems are the accounting predecessor because they were the first entities controlled by the common parent entity. Under common control accounting, the SAOU and LOU Systems assets and liabilities are recorded at their book value with the balance of the acquisition proceeds recorded as an adjustment to parent equity. As a result, the previously reported amounts have been restated as discussed below, and as further detail in Note 4.

The accompanying consolidated financial statements and related notes reflect the historical financial data of the SAOU and LOU Systems acquired by Targa on April 16, 2004 combined with the results of operations for the North Texas System contributed to us by Targa from the date of its acquisition by Targa on October 31, 2005. The historical financial information is derived from the audited financial statements of Targa. The accompanying financial statements and related notes for the years ended December 31, 2007 and 2006 are presented combining the results of operations of the SAOU and LOU Systems with the operations of the North Texas System and present the results of operations, cash flows and changes in partners' capital/net parent investment for those periods. The accompanying financial statements and related notes for the year ended December 31, 2005 combine the results of operations for the SAOU and LOU Systems for the year then ended and the results of operations, cash flows and changes in partners' capital reflected in the audited historical financial statements of the North Texas System for the two-months after its acquisition by Targa.

Prior to the acquisition of the SAOU and LOU Systems and the contribution of the North Texas System, our Parent provided cash management services to us through a centralized treasury system. As a result, all of our charges and cost allocations covered by the centralized treasury system were deemed to have been paid to the Parent in cash, during the period in which the cost was recorded in the combined financial statements. In addition, cash receipts advanced by the Parent in excess/deficit of charges and cash allocations are reflected as contributions from/distributions to the Parent in our statements of partners' capital/net parent equity and our statements of cash flows. As a result of this accounting treatment, our working capital does not reflect any affiliate accounts receivable for intercompany commodity sales or any affiliate accounts payable for personnel and services and for intercompany product purchases prior to the acquisition and contribution. Consequently, we had negative working capital balances of 369.0 million at December 31, 2006. Despite the negative working capital balance, we generated operating cash flows of $124.4 million for the year ended December 31, 2006. Investing cash flows of $32.9 million for the year ended December 31, 2006 as well as distributions to Targa of $91.5 million were funded with operating cash flows.

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 7 for a discussion of the amounts and method of allocation. 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. The Partnership accounts for asset retirement obligations ("AROs") using SFAS 143, *"Accounting for Asset Retirement Obligations,"* as interpreted by Financial Interpretation "FIN" 47, *"Accounting for Conditional Asset Retirement Obligations."* Asset retirement obligations 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, an entity records 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 the entity at either the recorded amount or the entity will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost.

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The changes in our aggregate asset retirement obligations are as follows:

	Year Ended December 31, 2007	2006 (in thousands)	2005
Beginning of period	$ 2,888	$ 2,644	$ 630
Other	—	—	2,054
Change in estimate	32	(1)	(134)
Accretion expense	342	245	94
End of period	$ 3,262	$ 2,888	$ 2,644

Cash and Cash Equivalents. We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less. Targa operates a centralized cash management system whereby excess cash from most of its subsidiaries, held in separate bank accounts, is swept to a centralized account. See centralized cash management in Note 7 — Related Party Transactions.

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 Targa to concentrations of credit risk consist primarily of trade accounts receivable and derivative instruments. Management believes the risk is limited, as our customers represent a broad and diverse group of energy marketers and end users.

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 the allowance for doubtful accounts may be required.

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 on a straight-line basis, which approximates the interest method.

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.

Impairment of Long-Lived Assets. Management reviews property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. The carrying amount is deemed not recoverable if it exceeds the undiscounted sum of the cash flows expected to result from the use and eventual disposition of the asset. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. If the carrying amount is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. Management assesses the fair value of long-lived assets using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party comparable sales, internally developed discounted cash flow analysis and analysis from outside advisors.

Income Taxes. The Partnership is 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 adopted the provisions of FIN 48 *"Accounting for Uncertainty in Income Taxes"* on January 1, 2007. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Based on our evaluation, we have determined that there are no significant uncertain tax positions requiring recognition in our financial statements at the date of adoption or December 31, 2007. 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 State of Texas jurisdictions, and are open to federal and state income tax examinations for years 2006 forward. Presently, no income tax examinations are underway, and none have been announced. No potential interest or penalties were recognized at December 31, 2007.

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 at 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. Emerging Issues Task Force ("EITF") Issue 03-6, *"Participating Securities and the Two-Class Method Under FASB Statement No. 128"* addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its securities.

EITF 03-6 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.

EITF 03-6 does not impact the Partnership's overall net income or other financial results; however, in periods in which aggregate net income exceeds the Partnership's 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 the Partnership's aggregate earnings, as if distributed, is allocated to the incentive distribution rights of the general partner, even though the Partnership makes distributions on the basis of available cash and not earnings. In periods in which the Partnership's aggregate net income does not exceed its aggregate distributions for such period, EITF 03-6 does not have any impact on the Partnership's calculation of earnings per limited partner unit.

Price Risk Management (Hedging). The Partnership accounts for derivative instruments in accordance with SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended. Under SFAS 133, 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.

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.

The Partnership’s policy is to formally document all relationships between hedging instruments and hedged items, as well as its 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, the Partnership assesses 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.

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 the Partnership’s functional asset groups are as follows:

Asset Group	Range of Years
Natural gas gathering systems and processing facilities	15 to 25
Office and miscellaneous 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.

Revenue Recognition. The Partnership’s 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.

The Partnership recognizes 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, the Partnership receives 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 the Partnership receives for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee-based contracts, the Partnership receives a fee based on throughput volumes.

The Partnership generally reports revenues gross in the consolidated statements of operations, in accordance with EITF 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Except for fee-based contracts, the Partnership acts 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. SFAS 131, *"Disclosures about Segments of an Enterprise and Related Information,"* establishes standards for reporting information about operating segments. The Partnership operates in one segment only, the natural gas gathering and processing segment.

Share-Based Employee Compensation. Targa Investments and the Partnership have stock-based compensation plans covering our employees and their respective Boards of Directors. We account for awards under these plans utilizing the fair value recognition provisions of SFAS 123R, "*Share-Based Payment*." Please see Note 11.

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.

Recent Accounting Pronouncements.

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, "Fair Value Measurements" ("SFAS 157") which 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 while the effective date for nonfinancial and financial assets and liabilities that are recognized on a recurring basis is effective beginning January 1, 2008. The Company has determined that the adoption of SFAS 157 will not have a material impact on its consolidated financial statements.

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,"* which is effective for fiscal years beginning after November 15, 2007, with early adoption permitted. 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. We are currently reviewing this new accounting standard and the impact, if any; it will have on our financial statements.

In December 2007, the FASB issued SFAS 160, "*Noncontrolling Interests in Consolidated Financial Statements — An Amendment of ARB No. 51."* SFAS 160 establishes new accounting and reporting standard for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS 160 is effective for fiscal periods, and interim periods within those fiscal years, beginning on or after December 15,

2008. We are currently reviewing this new accounting standard and the impact, if any, it will have on our financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), "*Business Combinations*" ("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. We are currently reviewing this new accounting standard and the impact, if any, it will have on our financial statements.

Note 4 — Acquisitions

On February 14, 2007, we had Targa's ownership interests in the North Texas System contributed to us. On October 24, 2007, we acquired Targa's ownership interests in Targa Texas Field Services LP (the "SAOU System") and Targa Louisiana Field Services LLC (the "LOU System"). As required by 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).

The predecessor entity for us is 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, following our acquisition of the North Texas System from Targa on February 14, 2007, we recognized the assets and liabilities acquired 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, as all of the North Texas System's equity accounts were also carried forward intact initially, and subsequently adjusted due to the cash consideration we paid for the acquired net assets.

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 consolidated financial statements and all other financial information included in this report have been restated to assume that the transfer of the North Texas System net assets from Targa to us had occurred at the date when both the North Texas System and the SAOU and LOU Systems met the accounting requirements for entities under common control (October 31, 2005). As a result, financial statements and financial information presented for prior periods in this report have been restated.

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table presents the impact on our consolidated financial position at December 31, 2006, adjusted for the acquisition of the SAOU and LOU Systems from Targa.

	SAOU/LOU System	North Texas System (in thousands)	Targa Resources Partners LP
ASSETS			
Current assets:			
Trade receivables	$ 60,249	$ 1,310	$ 61,559
Assets from risk management activities	8,433	17,250	25,683
Other	958	—	958
Total current assets	69,640	18,560	88,200
Property, plant, and equipment, net	224,463	1,064,108	1,288,571
Debt issue costs allocated from Parent	3,741	17,612	21,353
Long-term assets from risk management activities	310	15,541	15,851
Other long-term assets	2,396	—	2,396
Total assets	$ 300,550	$ 1,115,821	$ 1,416,371
LIABILITIES AND PARTNERS' CAPITAL			
Current liabilities:			
Accounts payable and other liabilities	$ 81,489	$ 31,621	$ 113,110
Current maturities of debt allocated from Parent	59,664	281,083	340,747
Liabilities from risk management activities	3,296	—	3,296
Total current liabilities	144,449	312,704	457,153
Long-term debt allocated from Parent	123,720	582,877	706,597
Long-term liabilities from risk management activities	455	96	551
Other long-term liabilities	1,629	4,528	6,157
Commitments and contingencies			
Partners' capital:			
Net parent investment	30,176	184,773	214,949
Other comprehensive income	121	30,843	30,964
Total partners' capital	30,297	215,616	245,913
Total liabilities and partners' capital	$ 300,550	$ 1,115,821	$ 1,416,371

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following tables present the impact on the consolidated statements of operations, adjusted for the acquisition of the SAOU and LOU Systems from Targa, for the periods presented:

	For the Year Ending December 31, 2006		
	SAOU/LOU System	North Texas System	Targa Resources Partners LP
		(in thousands)	
Revenues from third parties	$ 936,712	$ 15,224	$ 951,936
Revenues from affiliates	416,984	369,605	786,589
Total operating revenues	1,353,696	384,829	1,738,525
Costs and expenses:			
Product purchases from third parties	926,264	268,487	1,194,751
Product purchases from affiliates	322,071	846	322,917
Operating expenses	24,973	24,102	49,075
Depreciation and amortization expense	13,999	55,958	69,957
General and administrative expense	9,159	6,904	16,063
	1,296,466	356,297	1,652,763
Income from operations	57,230	28,532	85,762
Other expense:			
Interest expense allocated from Parent	15,115	72,910	88,025
Gain on mark-to-market derivative contracts	(16,756)	—	(16,756)
Income (loss) before income taxes	58,871	(44,378)	14,493
Deferred income tax expense	394	2,532	2,926
Net income (loss)	$ 58,477	$ (46,910)	$ 11,567

	SAOU/LOU System For The Year Ended December 31, 2005	North Texas System For the Two Months Ended December 31, 2005	Targa Resources Partners LP Total
		(in thousands)	
Revenues from third parties	$ 1,088,719	$ 22,192	$ 1,110,911
Revenues from affiliates	8,587	52,952	61,539
Total operating revenues	1,097,306	75,144	1,172,450
Costs and expenses:			
Product purchases from third parties	986,705	54,981	1,041,686
Product purchases from affiliates	19,987	11	19,998
Operating expenses	20,900	3,494	24,394
Depreciation and amortization expense	13,919	9,150	23,069
General and administrative expense	15,658	1,063	16,721
	1,057,169	68,699	1,125,868
Income from operations	40,137	6,445	46,582
Other expense:			
Interest expense allocated from Parent	9,635	11,542	21,177
Loss on mark-to-market derivative contracts	11,973	—	11,973
Loss on debt extinguishment	3,701	—	3,701
Income (loss) before income taxes	14,828	(5,097)	9,731
Deferred income tax expense	—	—	—
Net income (loss)	$ 14,828	$ (5,097)	$ 9,731

Note 5 — 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 held by Targa GP Inc. and Targa LP Inc. The 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 April 2008.

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.

Note 6 — Net Income per Limited Partner Unit

The Partnership's 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 weighted average number of outstanding limited partner units during the period.

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit reflects the potential dilution of common equivalent units that could occur if securities or other contracts to issue common units were exercised or converted into common units.

Due to the timing of our IPO, a pro-rated distribution for the first quarter of 2007 of $0.16875 per unit (approximately $5.3 million) was declared by the Board of Directors of our general partner on April 23, 2007 and paid on May 15, 2007. A distribution for the second quarter of 2007 of $0.3375 per unit (approximately $10.6 million) was declared on July 23, 2007 and paid on August 14, 2007 to unitholders of record as of the close of business on August 2, 2007. A distribution of $0.3375 per unit (approximately $10.6 million) was declared on October 24, 2007 and paid on November 14, 2007. A distribution of $0.3975 (approximately $18.7 million) for the fourth quarter of 2007 was declared on January 24, 2008 and was paid on February 14, 2008.

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table illustrates our calculation of net income per limited and subordinated partner unit for the year ended December 31, 2007:

		SAOU/LOU System		North Texas System	
	Year Ended December 31, 2007	Targa Resources Partners LP Oct. 24, 2007 to Dec. 31, 2007	SAOU/LOU Jan. 1, 2007 to Oct. 23, 2007	Targa Resources Partners LP Feb. 14, 2007 to Dec. 31, 2007	Targa North Texas LP Jan. 1, 2007 to Feb. 13, 2007
	(in thousands, except unit and per unit information)				
Revenues from third parties	$ 630,773	$ 129,916	$ 483,766	$ 13,156	$ 3,935
Revenues from affiliates	1,030,696	139,616	472,746	380,165	38,169
	1,661,469	269,532	956,512	393,321	42,104
Costs and expenses:					
Product purchases	1,406,797	242,214	858,007	277,881	28,695
Operating expenses, excluding DD&A	50,931	6,837	19,270	22,008	2,816
Depreciation and amortization expense	71,756	2,747	11,663	50,421	6,925
General and administrative expense	18,927	965	9,018	8,242	702
Loss (gain) on sale of assets	(296)	—	(298)	2	—
	1,548,115	252,763	897,660	358,554	39,138
Income from operations	113,354	16,769	58,852	34,767	2,966
Other expense					
Interest expense, net	21,998	4,261	—	17,737	—
Interest expense allocated from Parent	19,436	—	9,609	—	9,827
Loss/(gain) on mark-to-market derivative contracts	30,221	—	30,221	—	
Other	(30)	(7)	(23)	—	—
Income (loss) before income taxes	41,729	12,515	19,045	17,030	(6,861)
Deferred income tax expense	1,479	99	—	1,380	—
Net income (loss)	40,250	12,416	19,045	15,650	(6,861)
Less: Net income attributable to predecessor operations					
For the period 1/1-2/13/2007 for North Texas	(6,861)		—		(6,861)
For the period 1/1-10/23/2007 for SAOU/LOU	19,045		19,045		—
Total	12,184		$ 19,045		$ (6,861)
Net income allocable to partners	28,066				
General partner interest in net income	561	248		313	
Net income available to common and subordinated unitholders	$ 27,505	$ 12,168		$ 15,337	
Basic net income per common and subordinated unit	$ 0.81	$ 0.36		$ 0.45	
Diluted net income per common and subordinated unit	$ 0.81	$ 0.36		$ 0.45	
Basic average number of common and subordinated units outstanding	33,986	33,986		33,986	
Diluted average number of common and subordinated units outstanding	33,994	33,994		33,994	

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.

The calculation of net income per limited and subordinated partner unit for the year ended December 31, 2006 and prior is not presented as the Partnership did not have any outstanding units until we completed our IPO on February 14, 2007.

Note 7 — 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 the Omnibus Agreement, other than the indemnification provisions described in Note 13, 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.

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 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. The Partnership routinely conducts 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 the Partnership's expenditures were paid through Targa, resulting in inter-company 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 SAOU and LOU Systems.

Allocations

Allocation of costs. The employees supporting the Partnership's operations are employees of Targa. The Partnership's financial statements include costs allocated to it 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 the Partnership were based on identification of Targa's resources which directly benefit the Partnership and its proportionate share of costs based on the Partnership's 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 the Partnership 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 in cash.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. Prior to January 1, 2007, the Partnership's 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.

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the sales to and purchases from affiliates of Targa, payments made or received by Targa on behalf of the Partnership and allocations of costs from Targa which were settled through adjustments to partners' capital. Management believes these transactions are executed on terms that are fair and reasonable.

		SAOU/LOU System		North Texas System			
	Year Ended December 31, 2007	Targa Resources Partners LP Oct. 24, 2007 to Dec. 31, 2007	SAOU/LOU Jan 1, 2007 to Oct. 23, 2007	Targa Resources Partners LP Feb. 14, 2007 to Dec. 31, 2007	Targa North Texas LP Jan. 1, 2007 to Feb 13, 2007	Year Ended December 31, 2006	Year Ended December 31, 2005
				(in thousands)			
Cash							
Sales to affiliates	$ (1,030,696)	$ (139,616)	$ (472,746)	$ (380,165)	$ (38,169)	$ (786,589)	$ (61,539)
Purchases from affiliates	191,064	51,031	139,108	848	77	322,917	19,998
Allocations of general & administrative expenses — pre IPO	8,831	—	8,129	—	702	16,062	16,721
Allocations of general & administrative expenses under Omnibus Agreement	5,095	746	—	4,349	—	—	—
Allocated interest	19,436	—	9,598	—	9,838	88,025	21,177
Receivable from affiliates to be settled in cash	87,547	65,477	—	22,070	—	—	—
Receipts (Payments) made by the Parent	584,561	22,362	182,268	352,898	27,033	268,043	(99)
	$ (134,162)	$ —	(133,643)	$ —	$ (519)	$ (91,542)	$ (3,742)
Noncash							
Initial contribution by Parent			$ —		$ —	$ —	$ 219,879
Allocation of Parent debt repayments			59,400		—	5,979	146,907
Allocation of Parent incremental debt borrowings			—		—	—	(227,106)
Net settlement of allocated indebtedness and debt issue costs			121,145		180,656	5,903	6,229
Net contribution of affiliated receivables			145,606		38,856	—	—
Parent settlement of risk management activities			—		—	1,774	(3,384)
Other			3,452		—	272	—
			329,603		219,512	13,928	142,525
			$ 195,960		$ 218,993	$ (77,614)	$ 138,783

Centralized Cash Management

Prior to the contribution of the assets of the North Texas, SAOU and LOU Systems, Targa operated a cash management system whereby the excess cash from these subsidiaries was held in separate bank accounts and swept to a centralized corporate account. After the contribution of the assets from these systems, the Partnership maintained its own 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. Prior to February 14, 2007, the cash accounts of the Partnership were part of Targa's centralized cash management system. After this date, the Partnership maintains its own cash management system. For the period from January 1, 2007 through February 13, 2007, deemed net capital distributions from the Partnership were $0.5 million.

For the SAOU and LOU Systems, the same centralized cash management system was also maintained until October 23, 2007. After this date, the SAOU and LOU Systems transactions were cleared as part of the Partnership's cash management system. For the period from January 1, 2007 though October 23, 2007, deemed net capital distributions from the Partnership were $133.6 million.

Other

Commodity hedges. We have entered into various commodity derivative transactions with Merrill Lynch Commodities Inc. ("MLCI"), an affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated ("Merrill Lynch"). Merrill Lynch holds an equity interest in the holding company that indirectly owns our general partner. Under the terms of these various commodity derivative transactions, MLCI has agreed to pay us specified fixed prices in relation to specified notional quantities of natural gas and condensate over periods ending in 2010, and we have agreed to pay MLCI floating prices based on published index prices of such commodities for delivery at specified locations. The following table shows our open commodity derivatives with MLCI as of December 31, 2007:

Period	Commodity	Instrument Type	Daily Volumes	Average Price	Index
Jan 2008 — Mar 2008	Natural gas	Swap	1,650 MMBtu	$ 8.47 per MMBtu	NY-HH
Jan 2008 — Dec 2008	Natural gas	Swap	3,847 MMBtu	8.76 per MMBtu	IF-Waha
Jan 2009 — Dec 2009	Natural gas	Swap	3,556 MMBtu	8.07 per MMBtu	IF-Waha
Jan 2010 — Dec 2010	Natural gas	Swap	3,289 MMBtu	7.39 per MMBtu	IF-Waha
Jan 2008 — Mar 2008	NGL	Swap	470 Bbl	1.39 per gallon	OPIS-MB
Jan 2008 — Dec 2008	NGL	Swap	3,175 Bbl	1.06 per gallon	OPIS-MB
Jan 2009 — Dec 2009	NGL	Swap	3,000 Bbl	0.98 per gallon	OPIS-MB
Jan 2008 — Dec 2008	Condensate	Swap	264 Bbl	72.66 per barrel	NY-WTI
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

At December 31, 2007, the fair value of all these open positions is a liability of $25.6 million. During 2007, we paid MLCI $1.9 million to settle payments due under hedge transactions. During 2006, Merrill Lynch paid us $4.2 million in commodity derivative settlements. There were no commodity derivative settlements with Merrill Lynch prior to 2006.

Note 8 — Property, Plant, and Equipment

Property, plant, and equipment and accumulated depreciation were as follows at the dates indicated:

	December 31, 2007	December 31, 2006
	(in thousands)	
Gathering and processing systems	$ 1,363,791	$ 1,362,980
Other property and equipment	70,164	28,664
	1,433,955	1,391,644
Accumulated depreciation	(174,361)	(103,073)
	$ 1,259,594	$ 1,288,571

Note 9 — Long-Term Debt

Pre-IPO Indebtedness. In April 2004, Targa acquired the SAOU and LOU Systems from ConocoPhillips for $247 million of which $124 million of the acquisition costs was borrowed and allocated to the SAOU and LOU Systems. The entities holding the SAOU and LOU Systems provided a guarantee of this indebtedness. This indebtedness was also secured by a collateral interest in both the equity of the entities holding the SAOU and LOU Systems as well as their assets.

In October 2005, Targa completed the DMS acquisition, which included the North Texas System. A substantial portion of the acquisition was financed through borrowings. Following the 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. 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.

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 anum). 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 is 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 revolving credit facility to the affiliate debt balance for the period from January 1, 2007 to February 13, 2007.

Post-IPO Indebtedness. On February 14, 2007, we entered into a credit agreement which provides for a five-year $500 million revolving credit facility with a syndicate of financial institutions. The revolving credit facility bears interest at the Partnership's 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 the Partnership's total leverage ratio, or LIBOR plus an applicable margin ranging from 1.0% to 2.25% dependent on the Partnership's total leverage ratio. The Partnership initially borrowed $342.5 million under its credit facility, and concurrently repaid $48.0 million under its 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 the Partnership. Our credit facility is secured by substantially all of our assets. Our weighted average interest rate on outstanding borrowings under our credit facility for the period from February 14, 2007 to December 31, 2007 was 6.7%.

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 five-year $500 million senior secured revolving credit facility to increase the 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 senior secured revolving credit facility. Substantially all of the assets of the Partnership (North Texas, SAOU and LOU Systems) are currently pledged as collateral on our $750 million 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.

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 5.00 to 1.00 on the last day of any fiscal quarter ending on or after September 30, 2007. 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.

As of December 31, 2007, we had approximately $97.8 million available under our revolving credit facility, after giving effect to our outstanding borrowings of $626.3 million and the issuance of $25.9 million of letters of credit.

Note 10 — Derivative Instruments and Hedging Activities

At December 31, 2007 and 2006, OCI included $74.0 million of unrealized net losses and $30.5 million ($30.2 million, net of tax) of unrealized net gains, respectively, on commodity hedges.

For the years ended December 31, 2007, 2006 and 2005 deferred net gains/(losses) on commodity hedges of $1.0 million, ($0.8) million and $10.4 million were reclassified from OCI to revenues, respectively. There were no adjustments for hedge ineffectiveness for the years ended December 31, 2007, 2006 or 2005.

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At December 31, 2007, OCI also included $1.2 million of unrealized losses on interest rate hedges. At December 31, 2006, OCI also included $0.6 million of unrealized gains on interest rate hedges allocated from Targa. In connection with our IPO, all allocated debt was repaid or retired, and the associated allocated interest rate swaps were also retired.

For the years ended December 31, 2007, 2006 and 2005, deferred net gain/(losses) on interest rate hedges of ($0.2) million, ($0.5) million and $0.1 million were reclassified from OCI to net interest expense, respectively. There were no adjustments for hedge ineffectiveness for the years ended December 31, 2007, 2006 or 2005.

At December 31, 2007, deferred net losses of $36.4 million on commodity hedges and $0.3 million on interest rate hedges recorded in OCI are expected to be reclassified to expense during the next twelve months.

At December 31, 2007, we had the following hedge arrangements which will settle during the years ended December 31, 2008 thru 2012:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per Day 2008	2009	2010	2011	2012	Fair Value (in thousands)
Natural Gas Purchases								
Swap	NY-HH	8.34	1,467	—	—	—	—	$ (341)
			1,467	—	—	—	—	(341)
Natural Gas Sales								
Swap	IF-HSC	8.09	2,328	—	—	—	—	513
Swap	IF-HSC	7.39	—	1,966	—	—	—	(551)
			2,328	1,966	—	—	—	(38)
Swap	IF-NGPL MC	8.43	6,964	—	—	—	—	4,475
Swap	IF-NGPL MC	8.02	—	6,256	—	—	—	1,110
Swap	IF-NGPL MC	7.43	—	—	5,685	—	—	(667)
Swap	IF-NGPL MC	7.34	—	—	—	2,750	—	(387)
Swap	IF-NGPL MC	7.18	—	—	—	—	2,750	(435)
			6,964	6,256	5,685	2,750	2,750	4,096
Swap	IF-Waha	8.20	7,389	—	—	—	—	3,000
Swap	IF-Waha	7.61	—	6,936	—	—	—	(618)
Swap	IF-Waha	7.38	—	—	5,709	—	—	(1,288)
Swap	IF-Waha	7.36	—	—	—	3,250	—	(709)
Swap	IF-Waha	7.18	—	—	—	—	3,250	(789)
			7,389	6,936	5,709	3,250	3,250	(404)
Total Swaps			16,681	15,158	11,394	6,000	6,000	3,654
Floor	IF-NGPL MC	6.55	1,000	—	—	—	—	218
Floor	IF-NGPL MC	6.55	—	850	—	—	—	171
			1,000	850	—	—	—	389
Floor	IF-Waha	6.85	670	—	—	—	—	140
Floor	IF-Waha	6.55	—	565	—	—	—	93
			670	565	—	—	—	233
Total Floors			1,670	1,415	—	—	—	622
Basis Swap Jan 2008 Rec IF-HH minus $0.01, pay GD-HH, 403,000 MMBtu								6
								$ 3,941

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

NGLs

Instrument Type	Index	Avg. Price $/gal	Barrels per day 2008	2009	2010	2011	2012	Fair Value (in thousands)
NGL Sales								
Swap	OPIS-MB	1.02	7,127	—	—	—	—	$ (40,051)
Swap	OPIS-MB	0.96	—	6,248	—	—	—	(20,573)
Swap	OPIS-MB	0.91	—	—	4,809	—	—	(5,506)
Swap	OPIS-MB	0.92	—	—	—	3,400	—	(3,210)
Swap	OPIS-MB	0.92	—	—	—	—	2,700	(2,030)
			7,127	6,248	4,809	3,400	2,700	$ (71,370)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per day 2008	2009	2010	2011	2012	Fair Value (in thousands)
Condensate Sales								
Swap	NY-WTI	70.68	384	—	—	—	—	$ (3,013)
Swap	NY-WTI	69.00	—	322	—	—	—	(2,008)
Swap	NY-WTI	68.10	—	—	301	—	—	(1,705)
Total Swaps			384	322	301	—	—	(6,726)
Floor	NY-WTI	60.50	55	—	—	—	—	2
Floor	NY-WTI	60.00	—	50	—	—	—	9
Total Floors			55	50	—	—	—	11
			439	372	301	—	—	$ (6,715)

Customer Hedges

Period	Commodity	Instrument Type	Daily Volume	Average Price	Index	Fair Value (in thousands)
Purchases						
Jan 2008 — June 2008	Natural gas	Swap	8,440 MMBtu	7.23 per MMBtu	NY-HH	$ 8
Sales						
Jan 2008 — June 2008	Natural gas	Fixed price sale	8,440 MMBtu	7.23 per MMBtu	NY-HH	(8)
						$ —

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 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.

Our earnings are also affected by use of the mark-to-market method of accounting as required under SFAS 133 for derivative financial instruments that do not qualify for hedge accounting. 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 2007, 2006 and 2005, we recorded mark-to-market gains /(losses) of ($30.2) million, $16.8 million and ($12.0) million, respectively. At December 31, 2007, all of our derivative financial instruments qualify for hedge accounting.

In December 2007, we entered into interest rate swaps with a notional amount of $200 million. At December 31, 2007, we had the following open interest rate swaps:

Effective Date	Expiration Date	Notional Amount	Index	Fixed Rate
12/13/2007	1/24/2011	$ 50,000,000	3 Month USD LIBOR	4.0775%
12/18/2007	1/24/2011	$ 50,000,000	3 Month USD LIBOR	4.2100%
12/21/2007	1/24/2012	$ 50,000,000	3 Month USD LIBOR	4.0750%
12/21/2007	1/24/2012	$ 50,000,000	3 Month USD LIBOR	4.0750%

Each of these interest rate swaps have been designated as cash flow hedges of variable rate interest payments on $50 million in borrowings under our revolving credit facility. At December 31, 2007, the fair value of our interest rate swaps was $1.2 million.

Note 11 — Share-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. We account for awards under the Plan utilizing the fair value recognition provisions of SFAS 123R, "*Share-Based Payment*."

Non-Employee Director Grants

In connection with our IPO, our general partner made equity-based awards of 16,000 restricted common units of the Partnership (2,000 restricted common units in the Partnership to each of the Partnership'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 2007, we recognized compensation expense of $180,000 related to these awards. We estimate that the remaining fair value of $156,000 will be recognized in expense over the next 26 months.

Note 12 — Income Taxes

We are not a taxable entity for United States Federal income tax purposes. Taxes on our net income are generally borne by our unitholders through allocations of taxable income pursuant to the partnership agreement. In May 2006, Texas substantially revised its tax rules and imposed a new tax based on modified gross margin, beginning in 2007. Pursuant to the guidance of SFAS 109, *"Accounting for Income Taxes,"* we have accounted for this tax as an income tax. Our income tax expense of $1.5 million for the year ended December 31, 2007, was computed by applying a 1.0% state income tax rate to taxable margin, as defined in the Texas statute.

Note 13 — Commitments and Contingencies

Contractual obligations pertain to a natural gas pipeline capacity agreement on certain interstate pipelines, operating leases and AROs. Future non-cancelable commitments related to these obligations are presented below.

	Payments Due by Period						
Contractual Obligations	Total	2008	2009	2010 (in thousands)	2011	2012	2013 & Thereafter
Operating lease obligations	$ 142	$ 110	$ 32	$ —	$ —	$ —	$ —
Capacity payments	16,777	9,201	5,306	1,492	778	—	—
Right of way	4,947	310	269	255	255	252	3,606
Asset retirement obligation	3,263	—	—	—	—	—	3,263
	$ 25,129	$ 9,621	$ 5,607	$ 1,747	$ 1,033	$ 252	$ 6,869

Total expenses related to operating lease obligations, capacity payments and right-of-way payments were $5.7 million, $3.2 million, and $0.5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Environmental

For environmental matters, the Partnership records liabilities when remedial efforts are probable and the costs are reasonably estimated in accordance with the American Institute of Certified Public Accountants Statement of Position 96-1, *"Environmental Remediation Liabilities."* Environmental reserves do not reflect management's assessment of the insurance coverage that may be applicable to the matters at issue. Management has assessed each of the matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success. This liability was transferred as part of the assets contributed to us at the time of our IPO.

Our environmental liability was $0.3 million at December 31, 2007, primarily for ground water assessment and remediation.

Under the Omnibus Agreement described in Note 7, 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 and 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.

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 LLC, along with ConocoPhillips Company ("ConocoPhillips") and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase certain ConocoPhillips assets, 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. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit. WTG's motion to reconsider and for a new trial was overruled. On January 2, 2008, WTG filed a notice of appeal. Targa will contest any appeal filed by WTG, but can give no assurances regarding the outcome of the proceeding.

Note 14 — Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate in the midstream energy industry. Its business activities include gathering, transporting and processing of natural gas, NGLs and crude oil. As such, its 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 its 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 its 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 will 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 7.

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)

The Partnership's results of operations by quarter for the years ended December 31, 2007 and 2006, as adjusted to reflect the consideration of common control accounting and change in predecessor entities as discussed in Note 4, were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(Dollars in thousands, except per unit amounts)				
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)	(10,627)	13,811	14,392	22,674	40,250
less: net income (loss) attributable to predecessor operations	(12,780)	9,771	10,523	4,670	12,184
Net income available to partners	2,153	4,040	3,869	18,004	28,066
General partner interest in net income	43	81	77	360	561
Net income available to common and subordinated unitholders	$ 2,110	$ 3,959	$ 3,792	$ 17,644	$ 27,505
Basic income per limited partner unit	$ 0.07	$ 0.13	$ 0.12	$ 0.42	$ 0.81
Basic number of units	30,848	30,848	30,848	41,795	33,986
Diluted number of units	30,852	30,856	30,857	41,805	33,994
Year Ended December 31, 2006:					
Revenues	$ 523,858	$ 453,721	$ 401,267	$ 359,679	$ 1,738,525
Operating income	24,789	22,983	22,869	15,121	85,762
Net income (loss)	14,925	(3,681)	8,241	(7,918)	11,567
Basic income per limited partner unit(a)	—	—	—	—	—

(a) Total basic net income per limited partner unit was not calculated as Partner Units were not outstanding as of December 31, 2006.

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following tables present the impact on the condensed consolidated statement of operation, adjusted for the acquisition of the SAOU and LOU Systems from Targa, for the periods presented:

	For the Three Months Ended March 31, 2007		
	SAOU/LOU System	North Texas System	Targa Resources Partners LP
		(in thousands)	
Revenues from third parties	$ 134,106	$ 6,084	$ 140,190
Revenues from affiliates	121,082	87,509	208,591
Total operating revenues	255,188	93,593	348,781
Costs and expenses:			
Product purchases from third parties	190,709	63,445	254,154
Product purchases from affiliates	40,101	243	40,344
Operating expenses	6,184	5,968	12,152
Depreciation and amortization expense	3,843	14,195	18,038
General and administrative expense	1,776	1,578	3,354
	242,613	85,429	328,042
Income from operations	12,575	8,164	20,739
Other expense:			
Interest expense allocated from Parent	3,616	9,827	13,443
Interest expense, net	—	2,705	2,705
Loss on mark-to-market derivative contracts	14,880	—	14,880
Other	(21)	—	(21)
Income before income taxes	(5,900)	(4,368)	(10,268)
Deferred income tax expense	21	338	359
Net income	$ (5,921)	$ (4,706)	$ (10,627)

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For the Three Months Ending June 30, 2007			For the Six Months Ending June 30, 2007		
	SAOU/LOU System	North Texas System	Targa Resources Partners LP	SAOU/LOU System (restated)a	North Texas System	Targa Resources Partners LP
	(in thousands)					
Revenues from third parties	$ 170,849	$ 4,300	$ 175,149	$ 304,955	$ 10,384	$ 315,339
Revenues from affiliates	156,363	102,103	258,466	277,445	189,612	467,057
Total operating revenues	327,212	106,403	433,615	582,400	199,996	782,396
Costs and expenses:						
Product purchases from third parties	236,159	74,306	310,465	426,868	137,751	564,619
Product purchases from affiliates	60,965	271	61,236	101,066	514	101,580
Operating expenses	5,730	6,065	11,795	11,914	12,033	23,947
Depreciation and amortization expense	3,330	14,289	17,619	7,173	28,484	35,657
General and administrative expense	2,679	1,953	4,632	4,455	3,531	7,986
Loss (gain) on sale of assets	(315)	—	(315)	(315)	—	(315)
	308,548	96,884	405,432	551,161	182,313	733,474
Income from operations	18,664	9,519	28,183	31,239	17,683	48,922
Other expense:						
Interest expense allocated from Parent	2,732	—	2,732	6,348	9,827	16,175
Interest expense, net	—	5,154	5,154	—	7,859	7,859
Loss/(gain) on mark-to-market derivative contracts	6,122	—	6,122	21,002	—	21,002
Other	16	—	16	(5)	—	(5)
Income before income taxes	9,794	4,365	14,159	3,894	(3)	3,891
Deferred income tax expense	21	327	348	42	665	707
Net income	$ 9,773	$ 4,038	$ 13,811	$ 3,852	$ (668)	$ 3,184

a) Previously reported allocated interest expense from parent has been adjusted to reflect an additional allocation of interest expense of $1.5 million.

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For the Three Months Ending September 30, 2007			For the Nine Months Ending September 30, 2007		
	SAOU/LOU System	North Texas System	Targa Resources Partners LP	SAOU/LOU System	North Texas System	Targa Resources Partners LP
	(in thousands)					
Revenues from third parties	$ 142,036	$ 6,951	$ 148,987	$ 446,991	$ 17,335	$ 464,326
Revenues from affiliates	155,339	100,712	256,051	432,784	290,324	723,108
Total operating revenues	297,375	107,663	405,038	879,775	307,659	1,187,434
Costs and expenses:						
Product purchases from third parties	225,035	74,457	299,492	651,903	212,208	864,111
Product purchases from affiliates	38,042	228	38,270	139,108	742	139,850
Operating expenses	6,193	6,543	12,736	18,107	18,576	36,683
Depreciation and amortization expense	3,588	14,396	17,984	10,761	42,880	53,641
General and administrative expense	3,795	2,779	6,574	8,250	6,310	14,560
Loss (gain) on sale of assets	17	—	17	(298)	—	(298)
	276,670	98,403	375,073	827,831	280,716	1,108,547
Income from operations	20,705	9,260	29,965	51,944	26,943	78,887
Other expense:						
Interest expense allocated from Parent	2,806	—	2,806	9,154	9,827	18,981
Interest expense, net	—	5,059	5,059	—	12,918	12,918
Loss/(gain) on mark-to-market derivative contracts	7,367	—	7,367	28,369	—	28,369
Other	(12)	—	(12)	(17)	—	(17)
Income before income taxes	10,544	4,201	14,745	14,438	4,198	18,636
Deferred income tax expense	21	332	353	63	997	1,060
Net income	$ 10,523	$ 3,869	$ 14,392	$ 14,375	$ 3,201	$ 17,576

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For the Three Months Ending March 31, 2006		
	SAOU/LOU System	North Texas System	Targa Resources Partners LP
		(in thousands)	
Revenues from third parties	$ 353,613	$ 1,857	$ 355,470
Revenues from affiliates	73,995	94,393	168,388
Total operating revenues	427,608	96,250	523,858
Costs and expenses:			
Product purchases from third parties	283,059	67,694	350,753
Product purchases from affiliates	117,567	172	117,739
Operating expenses	5,826	5,944	11,770
Depreciation and amortization expense	3,364	13,720	17,084
General and administrative expense	135	1,588	1,723
	409,951	89,118	499,069
Income from operations	17,657	7,132	24,789
Other expense:			
Interest expense allocated from Parent	3,637	17,361	20,998
Loss/(gain) on mark-to-market derivative contracts	(11,134)	—	(11,134)
Income before income taxes	25,154	(10,229)	14,925
Deferred income tax expense	—	—	—
Net income	$ 25,154	$ (10,229)	$ 14,925

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For the Three Months Ending June 30, 2006			For the Six Months Ending June 30, 2006		
	SAOU/LOU System	North Texas System	Targa Resources Partners LP	SAOU/LOU System	North Texas System	Targa Resources Partners LP
	(in thousands)					
Revenues from third parties	$ 254,594	$ 2,871	$ 257,465	$ 608,207	$ 4,728	$ 612,935
Revenues from affiliates	106,453	89,803	196,256	180,448	184,196	364,644
Total operating revenues	361,047	92,674	453,721	788,655	188,924	977,579
Costs and expenses:						
Product purchases from third parties	236,869	64,657	301,526	519,928	132,350	652,278
Product purchases from affiliates	96,223	227	96,450	213,790	400	214,190
Operating expenses	6,455	5,599	12,054	12,281	11,543	23,824
Depreciation and amortization expense	3,365	13,719	17,084	6,729	27,439	34,168
General and administrative expense	1,957	1,667	3,624	2,092	3,255	5,347
	344,869	85,869	430,738	754,820	174,987	929,807
Income from operations	16,178	6,805	22,983	33,835	13,937	47,772
Other expense:						
Interest expense allocated from Parent	3,779	18,302	22,081	7,416	35,663	43,079
Loss/(gain) on mark-to-market derivative contracts	2,735	—	2,735	(8,399)	—	(8,399)
Income before income taxes	9,664	(11,497)	(1,833)	34,818	(21,726)	13,092
Deferred income tax expense	394	1,454	1,848	394	1,454	1,848
Net income	$ 9,270	$ (12,951)	$ (3,681)	$ 34,424	$ (23,180)	$ 11,244

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

	For the Three Months Ending September 30, 2006			For the Nine Months Ending September 30, 2006		
	SAOU/LOU System	North Texas System	Targa Resources Partners LP	SAOU/LOU System	North Texas System	Targa Resources Partners LP
			(in thousands)			
Revenues from third parties	$ 171,241	$ 3,505	$ 174,746	$ 779,448	$ 8,233	$ 787,681
Revenues from affiliates	128,060	98,461	226,521	308,508	282,657	591,165
Total operating revenues	299,301	101,966	401,267	1,087,956	290,890	1,378,846
Costs and expenses:						
Product purchases from third parties	212,981	72,182	285,163	732,909	204,532	937,441
Product purchases from affiliates	59,263	270	59,533	273,053	670	273,723
Operating expenses	5,857	6,362	12,219	18,138	17,905	36,043
Depreciation and amortization expense	3,397	14,274	17,671	10,126	41,713	51,839
General and administrative expense	1,930	1,882	3,812	4,022	5,137	9,159
	283,428	94,970	378,398	1,038,248	269,957	1,308,205
Income from operations	15,873	6,996	22,869	49,708	20,933	70,641
Other expense:						
Interest expense allocated from Parent	3,761	18,706	22,467	11,177	54,369	65,546
Loss/(gain) on mark-to-market derivative contracts	(8,373)	—	(8,373)	(16,771)	—	(16,771)
Income before income taxes	20,485	(11,710)	8,775	55,302	(33,436)	21,866
Deferred income tax expense	—	534	534	394	1,988	2,382
Net income	$ 20,485	$ (12,244)	$ 8,241	$ 54,908	$ (35,424)	$ 19,484

Note 16 — Subsequent Event

On January 24, 2008, our general partner approved a quarterly distribution of available cash of $0.3975 per unit (approximately $18.7 million), for the quarter ended December 31, 2007, payable on February 14, 2008 to unitholders of record as of the close of business on February 4, 2008.

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/A 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	—	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)).
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 (incorporate 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	—	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)).
10.5	—	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)).
10.6	—	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)).
10.7+	—	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)).

10.8+	—	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)).
10.9+	—	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 February 13, 2007 (File No. 001-33303)).
10.10+	—	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 22, 2008 (File No. 001-33303)).
10.11	—	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)).
10.12	—	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)).
10.13	—	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)).
10.14	—	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)).
10.15	—	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)).
10.16	—	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)).
10.17	—	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)).
10.18	—	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)).
10.19+	—	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)).
10.20+	—	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)).
10.21+	—	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)).
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.

Exhibit 21.1

Targa Resources Partners LP Subsidiaries

Targa Resources Operating GP LLC

Targa Resources Operating LP

Targa North Texas GP LLC

Targa North Texas LP

Targa Intrastate Pipeline LLC

Targa Resources Texas GP LLC

Targa Texas Field Services LP

Targa Louisiana Field Services LLC

Targa Louisiana Intrastate LLC

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 333-149200) of Targa Resources Partners LP of our report dated March 26, 2008 relating to the financial statements, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Houston, Texas
March 26, 2008

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 15(d)-(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;

(b) 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

(c) 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: March 31, 2008

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 15(d)-(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: March 31, 2008

By: /s/ Jeffrey J. McParland

Name: Jeffrey J. McParland
Title: Executive Vice President, Chief Financial Officer
and Treasurer of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP
(Principal Financial Officer)

**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, 2007 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 the Partnership

Date: March 31, 2008

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, 2007 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 and Treasurer of Targa Resources GP LLC, the general partner of the Partnership

Date: March 31, 2008

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.