Filed pursuant to Rule 424(b)(1)
Registration No. 333-146436
Registration No. 333-146809

PROSPECTUS

Targa Resources Partners LP

13,500,000 Common Units

Representing Limited Partner Interests

Targa Resources Partners LP is offering 13,500,000 common units representing limited partner interests. Our common units are traded on The NASDAQ Stock Market LLC under the symbol "NGLS." On October 18, 2007, the last reported sale price of our common units on The NASDAQ Stock Market LLC was $26.87 per common unit.

Investing in our common units involves risks. Please see "Risk Factors" beginning on page 16.

These risks assume completion of the acquisition of certain businesses described herein and include the following:

- We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to make cash distributions to holders of our common units and subordinated units at the minimum quarterly distribution rate under our cash distribution policy.
- Our cash flow is affected by natural gas and natural gas liquid prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units.
- 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 natural gas liquids, which depends on certain factors beyond our control. Any decrease in supplies of natural gas or natural gas liquids could adversely affect our business and operating results.
- 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 equity commodity volumes that are hedged decreases substantially over time.
- We will use the proceeds of this offering together with borrowings to purchase gathering systems in west Texas and southwest Louisiana. If the acquired businesses or future acquisitions do not perform as expected, our future financial performance may be negatively impacted.
- Targa Resources, Inc. controls our general partner, which has sole responsibility for conducting our business and managing our operations. Targa Resources, Inc. has conflicts of interest with us and may favor its own interests to your detriment.
- Targa Resources, Inc. is not limited in its ability to compete with us, which could limit our ability to acquire additional assets or businesses.
- Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.
- You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

	Per Common Unit	Total
Initial price to public	$ 26.870	$ 362,745,000
Underwriting Discount	$ 1.074	$ 14,499,000
Proceeds to Targa Resources Partners LP (before expenses)	$ 25.796	$ 348,246,000

We have granted the underwriters a 30-day option to purchase up to an additional 2,025,000 common units from us on the same terms and conditions as set forth above if the underwriters sell more than 13,500,000 common units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver our common units through the facilities of The Depository Trust Company on or about October 24, 2007.

Citi　Lehman Brothers　Goldman, Sachs & Co.　Merrill Lynch & Co.

UBS Investment Bank

Wachovia Securities

Credit Suisse

Deutsche Bank Securities

Raymond James

RBC Capital Markets

Sanders Morris Harris

October 18, 2007

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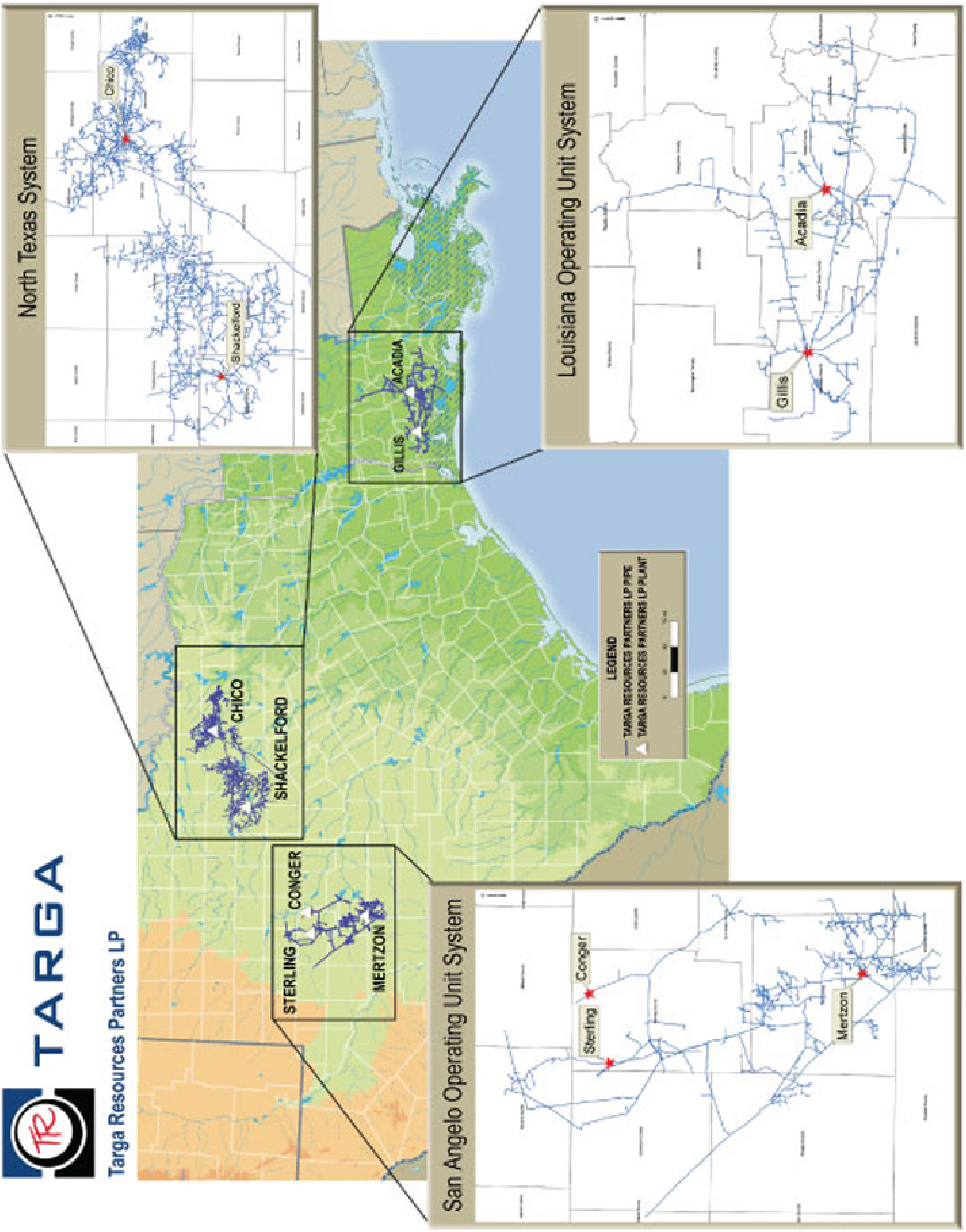

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You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date.

SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary may not contain all of the information that you should consider before investing in our common units. You should read the entire prospectus carefully, including the historical and pro forma financial statements and the notes to those financial statements. Unless indicated otherwise, the information presented in this prospectus assumes that the underwriters do not exercise their option to purchase additional units. You should read "Risk Factors" beginning on page 16 for more information about important risks that you should consider carefully before buying our common units. We include a glossary of some of the terms used in this prospectus as Appendix A. As used in this prospectus, unless we indicate otherwise: (1) "our," "we," "us," the "Partnership" and similar terms refer to Targa Resources Partners LP, together with our subsidiaries, (2) "Targa" refers to Targa Resources, Inc. and its subsidiaries and affiliates (other than us) and (3) references to our pro forma financial information refer to the historical financial information of the Predecessor Business described on page 12 of this prospectus as adjusted to give effect to certain transactions affected at the closing of our initial public offering, our proposed acquisition of the Acquired Businesses (as defined below) from Targa and this offering.

Targa Resources Partners LP

We are a growth-oriented Delaware limited partnership formed by 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 natural gas liquids, or NGLs, and NGL products. We currently operate in the Fort Worth Basin/Bend Arch in north Texas (the "Fort Worth Basin"), which is one of the most active natural gas basins in the U.S. as measured by drilling activity. 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.

Consistent with this strategy, we will acquire certain natural gas gathering and processing operations located in the Permian Basin of west Texas and southwest Louisiana from Targa for aggregate consideration of $705 million, subject to certain adjustments, concurrently with the closing of this offering. We believe this acquisition will increase our scale of operations, provide geographic diversity and position us to pursue future growth opportunities. At June 30, 2007, Targa had total assets of $3.4 billion (including the assets of the Partnership, which represent $1.1 billion of this amount). The Acquired Businesses (as defined below) to be purchased by us concurrently with the closing of this offering represent $297 million of this amount. Over time, Targa intends, but is not obligated, to offer us the opportunity to purchase substantially all of its remaining businesses.

Our operations currently consist of an extensive network of approximately 4,000 miles of integrated gathering pipelines that gather and compress natural gas received from approximately 2,650 receipt points in the Fort Worth Basin, two natural gas processing plants that compress, treat and process the natural gas and a fractionator that fractionates a portion of our raw NGLs produced in our processing operations into NGL products. These assets, together with the business conducted thereby, are collectively referred to as the "North Texas System." The North Texas System serves a fourteen-county natural gas producing region in the Fort Worth Basin that includes production from the Barnett Shale formation and other shallower formations. For more information on the North Texas System, please see "Business — Our Partnership."

Please see "Business — Strategies" and "Business — Competitive Strengths" for a discussion of our strategies and competitive strengths.

Description of the Acquired Businesses

On September 18, 2007, we entered into a purchase and sale agreement with Targa pursuant to which we will acquire certain natural gas gathering and processing systems located in the Permian Basin of west Texas and southwest Louisiana for aggregate consideration of $705 million, subject to certain adjustments, consisting of $697.6 million in cash and the value of the issuance to our general partner of 275,511 general partner units, enabling our general partner to maintain its general partner interest in us. This will increase our miles of natural gas gathering pipelines and our processing capacity by approximately 50% and 140%, respectively, and is expected to provide us with significant additional throughput volumes and cash flow. On September 25 and 26, 2007, Targa completed transactions to terminate certain out of the money NGL hedges associated with the Acquired Businesses and to enter into new hedges for approximately the same volume and term at then current market prices. Pursuant to the purchase and sale agreement for the Acquired Businesses, these hedging transactions will result in a $24.2 million increase to the purchase price we will pay to Targa for the Acquired Businesses. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations — The Acquired Businesses" for a description of the cash settlement of these hedges. The systems to be acquired, which we refer to as the "Acquired Businesses," consist of:

- The San Angelo Operating Unit System (the "SAOU System") — the SAOU System consists of the approximately 1,350 mile San Angelo natural gas gathering system, which is located in the Permian Basin of west Texas, and the Mertzon, Sterling and Conger processing plants with aggregate processing capacity of approximately 135 MMcf/d; and
- The Louisiana Operating Unit System (the "LOU System") — the LOU System consists of an approximately 700-mile natural gas gathering system, which is located in southwest Louisiana, the Gillis and Acadia processing plants with aggregate processing capacity of approximately 260 MMcf/d and an integrated fractionation facility at the Gillis processing plant with processing capacity of approximately 13 thousand barrels per day, or MBbls/d.

The SAOU System operates primarily under percent-of-proceeds contracts and the LOU System operates primarily under percent-of-proceeds and short-term wellhead purchase contracts. After giving effect to the acquisition of the Acquired Businesses, our aggregate contract profile for the first half of 2007 would have been approximately 82% percent-of-proceeds, approximately 1% fee and approximately 17% wellhead purchase/keep whole contracts, on a volume basis. 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.

Consistent with our strategy to mitigate commodity price exposure through prudent hedging arrangements, certain commodity price hedging instruments will be transferred to us in connection with our acquisition of the Acquired Businesses. The commodity risk exposure of the Acquired Businesses has been managed similarly to the North Texas System and we expect that the combined businesses will be managed to hedge the commodity price exposure associated with a significant portion of expected equity volumes of natural gas and NGLs in the near to mid-term. For more information on our commodity hedging activities, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosures about Market Risk — Summary of Our Hedges."

The closing of our acquisition of the Acquired Businesses is subject to the satisfaction of a number of conditions, including our ability to obtain satisfactory financing. At the closing of this offering, we anticipate that the following transactions will occur:

- we will issue 13,500,000 common units to the public, representing a 29.8% limited partner interest in us;
- we will borrow approximately $378.9 million under our amended credit facility;
- we will issue to our general partner 275,511 general partner units as partial consideration for the Acquired Businesses, enabling it to maintain its 2% general partner interest in us;

- we will use the net proceeds from this offering and borrowings under our amended credit facility to pay expenses associated with this offering and our amended credit facility and to pay consideration of approximately $697.6 million to Targa to purchase the Acquired Businesses; and
- we will use the remaining net proceeds to pay $24.2 million to Targa for certain hedge transactions associated with the Acquired Businesses effected on September 25 and 26, 2007, which is an adjustment to the purchase price for the Acquired Businesses.

We will use any net proceeds from the exercise of the underwriters' option to reduce outstanding borrowings under our amended credit facility.

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 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. Consistent with our acquisition of the Acquired Businesses, we expect to have the opportunity to make acquisitions directly from Targa in the future. 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. Targa has retained such flexibility because it believes it is in the best interests of its shareholders to do so. 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 will 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.

Following our acquisition of the Acquired Businesses and exclusive of its interest in us, Targa will own interests in or operate approximately 4,000 miles of natural gas pipelines and approximately 400 miles of NGL pipelines, with natural gas gathering systems covering approximately 4,200 square miles and 15 natural gas processing plants with access to natural gas supplies in the Permian basin and the Gulf of Mexico. Additionally, 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 65 MMBbls. The locations of Targa's assets provide it access to relatively stable natural gas supplies and proximity to end-use markets and liquid market hubs while positioning it to capitalize on growth opportunities from selected areas of the Permian Basin and from the increasing importation of LNG to the Gulf Coast.

Our Relationship with Warburg Pincus LLC

Warburg Pincus LLC ("Warburg Pincus") controls us through its ownership of securities in Targa Resources Investments Inc., the indirect parent of Targa, and a stockholders agreement among Targa Resources Investments Inc. and its owners. Warburg Pincus is a global private equity firm that over the past four decades has invested more than $26 billion in 575 companies in 30 countries, representing a variety of industries including energy, technology, media and telecommunications, financial services, healthcare and life sciences, retail, consumer and industrial and real estate.

Summary of Risk Factors

An investment in our common units involves risks associated with our business, regulatory and legal matters, our limited partnership structure and the tax characteristics of our common units. The following list of risk factors is presented as if we have completed the acquisition of the Acquired Businesses and is not exhaustive. Please see these and other risks described under "Risk Factors."

Risks Related to Our Business

- We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to make cash distributions to holders of our common units and subordinated units at the minimum quarterly distribution rate under our cash distribution policy.
- Our cash flow is affected by natural gas and NGL prices, and decreases in these prices could adversely affect our ability to make distributions to holders of our common units and subordinated units.
- 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 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 equity commodity volumes that are hedged decreases substantially over time.
- We will use the proceeds of this offering together with borrowings to purchase the Acquired Businesses. If the acquired businesses or future acquisitions do not perform as expected, our future financial performance may be negatively impacted.

Risks Inherent in an Investment in Us

- 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.
- The credit and business risk profile of our general partner and its owners could adversely affect our credit ratings and profile.
- 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.
- Targa is not limited in its ability to compete with us, which could limit our ability to acquire additional assets or businesses.
- Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

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 (the "IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you could be substantially reduced.

- If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted, and the costs of any IRS contest will reduce our cash available for distribution to you.
- You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.
- Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Partnership Structure and Management

Management of Targa Resources Partners LP

Targa Resources GP LLC, our general partner, manages our business and operations, and its board of directors and officers makes decisions on our behalf. All of the executive officers and some of the directors of Targa also serve as executive officers or directors of our general partner.

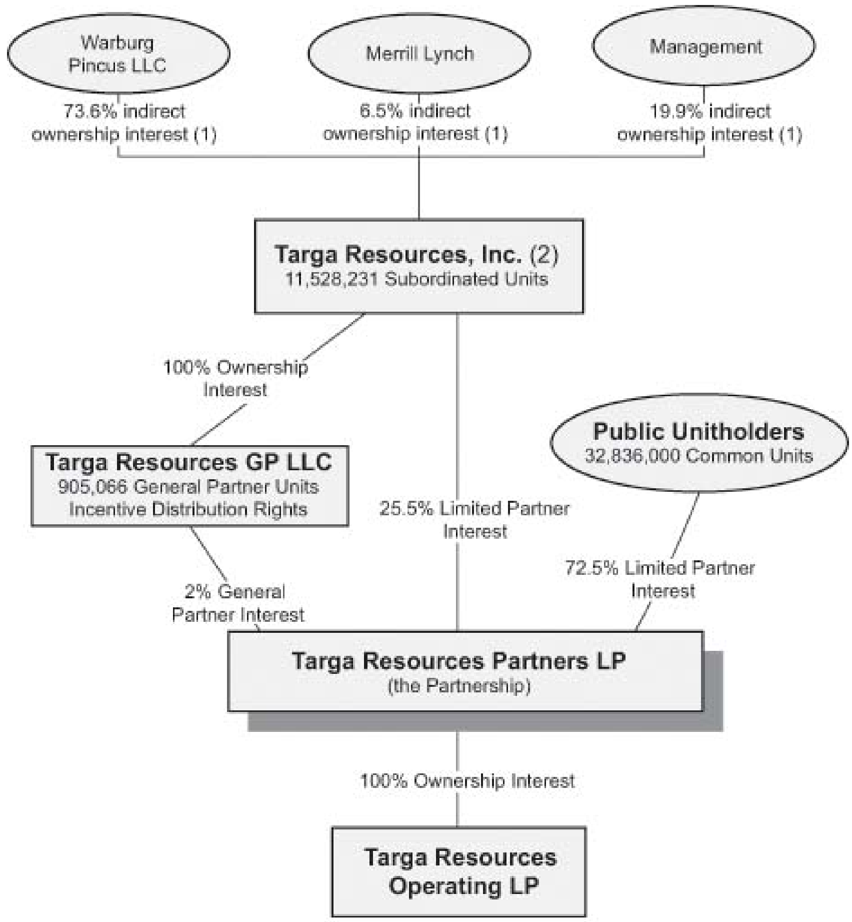
Unlike shareholders in a publicly traded corporation, our unitholders are not entitled to elect our general partner or its directors. Targa elected all seven members to the board of directors of our general partner and we have three directors that are independent as defined under the independence standards established by The NASDAQ Stock Market LLC. For more information about these individuals, please see “Management — Directors and Executive Officers.”

The diagram below depicts our organization and ownership after giving effect to this offering.

Simplified Organizational Structure

Ownership of Targa Resources Partners LP

Public Common Units	72.5%
Subordinated Units	25.5%
General Partner Units	2.0%
Total	100.0%



(1) Ownership percentages are presented on a fully-diluted basis.

(2) Targa Resources, Inc. is an indirect wholly-owned subsidiary of Targa Resources Investments Inc. Warburg Pincus LLC controls us through its ownership of securities in Targa Resources Investments Inc. and a stockholders agreement among Targa Resources Investments Inc. and its owners.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 1000 Louisiana, Suite 4300, Houston, Texas 77002 and our telephone number is (713) 584-1000. Our website is located at www.targaresources.com. We make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, or the SEC, available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

Summary of Conflicts of Interest and Fiduciary Duties

Targa Resources GP LLC, our general partner, has a legal duty to manage us in a manner beneficial to holders of our common units and subordinated units. This legal duty originates in statutes and judicial decisions and is commonly referred to as a "fiduciary duty." However, because our general partner is owned by Targa, the officers and directors of our general partner also have fiduciary duties to manage our general partner in a manner beneficial to Targa. As a result of this relationship, conflicts of interest may arise in the future between us and holders of our common units and subordinated units, on the one hand, and our general partner and its affiliates on the other hand. Our partnership agreement also provides that Targa is not restricted from competing with us.

For a more detailed description of the conflicts of interest and fiduciary duties of our general partner, please see "Conflicts of Interest and Fiduciary Duties."

The Offering

Common units offered to the public	13,500,000 common units or 15,525,000 common units if the underwriters exercise in full their option to purchase additional common units.
Units outstanding after this offering	32,836,000 common units and 11,528,231 subordinated units, representing a 72.5% and 25.5% limited partner interest in us, respectively (34,861,000 common units and 11,528,231 subordinated units, representing a 73.6% and 24.4% limited partner interest in us, respectively, if the underwriters exercise in full their option to purchase additional common units).
Use of proceeds	The net proceeds from this offering of common units will be approximately $348.2 million after deducting underwriting discounts but before estimated offering expenses. We will use the net proceeds of this offering of common units and borrowings of approximately $378.9 million under our amended credit facility to pay approximately: • $697.6 million of the $705.0 million aggregate consideration, subject to certain adjustments, to Targa to acquire the Acquired Businesses; • $24.2 million to Targa for certain hedge transactions associated with the Acquired Businesses effected on September 25 and 26, 2007, which is an adjustment to the purchase price for the Acquired Businesses; and • $5.3 million of estimated expenses associated with our acquisition of the Acquired Businesses and the related financing transactions, including this offering. In addition, we will issue to our general partner 275,511 general partner units as partial consideration for the Acquired Businesses, enabling it to maintain its 2% general partner interest in us. If the underwriters exercise their option to purchase additional common units, we will use the net proceeds to reduce outstanding borrowings under our amended credit facility. Please read “Use of Proceeds.”
Cash distributions	We paid a prorated quarterly cash distribution of $0.16875 per unit for the first quarter of 2007, or $1.35 per unit on an annualized basis, on May 15, 2007 to unitholders of record as of May 3, 2007. This distribution was for the period from February 14, 2007, the date of the closing of our initial public offering, through the end of the first quarter. We paid a quarterly cash distribution of $0.3375 per common unit for the second quarter of 2007, or $1.35 per unit on an annualized basis, on August 14, 2007 to unitholders of record as of August 2, 2007. Within 45 days after the end of each quarter, we distribute our available cash to unitholders of record on the applicable record date.

	In general, we will pay any cash distributions we make each quarter in the following manner: • first, 98% to the holders of common units and 2% to our general partner, until each common unit has received a minimum quarterly distribution of $0.3375 plus any arrearages from prior quarters; • second, 98% to the holders of subordinated units and 2% to our general partner, until each subordinated unit has received a minimum quarterly distribution of $0.3375; and • third, 98% to all unitholders, pro rata, and 2% to our general partner, until each unit has received an aggregate distribution of $0.3881. If cash distributions to our unitholders exceed $0.3881 per common unit in any quarter, our general partner will receive, in addition to distributions on its 2% general partner interest, increasing percentages, up to 48%, of the cash we distribute in excess of that amount. We refer to these distributions as "incentive distributions." Please see "Our Cash Distribution Policy."
Subordinated units	Targa owns all of our subordinated units. The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are entitled to receive the minimum quarterly distribution of $0.3375 per unit only after our common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages. The subordination period generally will end if we have earned and paid at least $0.3375 on each outstanding unit and general partner unit for any three consecutive, non-overlapping four-quarter periods ending on or after March 31, 2010. The subordination period will also end if the unitholders remove our general partner other than for cause and units held by our general partner and its affiliates are not voted in favor of such removal. When the subordination period ends, all remaining subordinated units will convert into common units on a one-for-one basis, and our common units will no longer be entitled to arrearages.
Early conversion of subordinated units	If we have earned and paid at least $2.025 (150% of the annualized minimum quarterly distribution) on each outstanding common unit, subordinated unit and general partner unit for any four-quarter period, the subordination period will terminate automatically and all of the subordinated units will convert into an equal number of common units. Please see "Our Cash Distribution Policy — Subordination Period."
General Partner's right to reset the target distribution levels	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 the same percentage increases above the reset minimum quarterly distribution amount as in our current target distribution levels. 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. For a more detailed description of our general partner's right to reset the target distribution levels upon which the incentive distribution payments are based and the concurrent right of our general partner to receive Class B units in connection with this reset, please see "Our Cash Distribution Policy — General Partner's Right to Reset Incentive Distribution Levels."
Issuance of additional units	We can issue an unlimited number of units without the consent of our unitholders. Please see "Units Eligible for Future Sale" and "The Partnership Agreement — Issuance of Additional Securities."
Limited voting rights	Our general partner manages and operates us. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner or its directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the holders of at least $66^2/_3$% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. Upon completion of this offering, our general partner and its affiliates will own an aggregate of 26.0% of our common and subordinated units. Please see "The Partnership Agreement — Voting Rights."
Limited call right	If at any time our general partner and its affiliates own more than 80% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price not less than the then-current market price of our common units.
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, 2010, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be 20% or less of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $1.35 per unit, we estimate that your average allocable federal taxable

	income per year will be no more than $0.27 per unit. Please see "Material Tax Consequences — Tax Consequences of Unit Ownership — Ratio of Taxable Income to Distributions."
Material tax consequences	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please see "Material Tax Consequences."
Trading	Our common units are traded on The NASDAQ Stock Market LLC under the symbol "NGLS."

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Summary Historical and Pro Forma Financial and Operating Data

The following table shows summary historical financial and operating data of Targa Resources Partners LP and the Predecessor Business and pro forma financial data of Targa Resources Partners LP for the periods and as of the dates indicated. We refer to the assets, liabilities and operations of the North Texas System contributed to us by Targa upon the closing of our initial public offering as the Predecessor Business. The Predecessor Business was acquired by Targa as part of Targa's acquisition of substantially all of Dynegy Inc.'s midstream business on October 31, 2005 (the "DMS Acquisition"). The summary historical financial data of the Predecessor Business as of and for the year ended December 31, 2004, the ten-month period ended October 31, 2005, the two-month period ended December 31, 2005 and the year ended December 31, 2006 are derived from the audited financial statements of the Predecessor Business. The summary historical financial data of the Predecessor Business as of and for the six months ended June 30, 2006 are derived from the unaudited financial statements of the Predecessor Business. The summary historical financial data as of and for the six months ended June 30, 2007 are derived from the unaudited financial statements of Targa Resources Partners LP.

The summary pro forma financial data for the period from March 12, 2004 to December 31, 2004, the years ended December 31, 2005 and 2006, the six months ended June 30, 2006 and 2007 and as of June 30, 2007 are derived from the unaudited pro forma financial statements of Targa Resources Partners LP included in this prospectus. The pro forma statements of operations for the year ended December 31, 2006 and for the six months ended June 30, 2007 have been prepared as if certain transactions effected at the closing of our initial public offering, the acquisition of the Acquired Businesses and this offering had taken place on January 1, 2006. The pro forma balance sheet as of June 30, 2007 has been prepared as if the acquisition of the Acquired Businesses and this offering had taken place on June 30, 2007. The Targa entities which purchased the Acquired Businesses were formed by Targa on March 12, 2004 and the results of operations of the Acquired Businesses are reflected in our pro forma financial statements from and after April 16, 2004, the date of Targa's acquisition of the Acquired Businesses from ConocoPhillips. The pro forma financial information for the period from March 12, 2004 to December 31, 2004, the year ended December 31, 2005, and the six months ended June 30, 2006 reflect the combined results of operations of the Predecessor Business and the Acquired Businesses for all periods when such businesses were under the common controlling ownership of Targa. Targa Resources Partners LP and the Acquired Businesses are controlled by a common parent entity, Targa. The acquisition of the Acquired Businesses by Targa Resources Partners LP is accounted for and presented under common control accounting. Under common control accounting, the Acquired Businesses' assets and liabilities are recorded at their book value with the balance of acquisition proceeds recorded as an adjustment to parent equity.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the historical combined and pro forma condensed financial statements and the accompanying notes beginning on page F-3.

	Predecessor Business					Targa Resources Partners LP	Targa Resources Partners LP					
	Dynegy		Targa North Texas LP				Pro Forma					
	Year Ended December 31, 2004	Ten Months Ended October 31, 2005	Two Months Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007	Period from March 12, 2004 to December 31, 2004	Year Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007
	(Audited)	(Audited)	(Audited)	(Audited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
	(In millions of dollars, except per unit, operating and price data)										
Statement of Operations Data:											
Total operating revenues	$ 258.6	$ 293.3	$ 75.1	$ 384.8	$ 188.9	$ 200.0	$ 603.9	$ 1,160.4	$ 1,755.3	$ 986.0	$ 761.4
Product purchases	$ 182.6	$ 210.8	$ 54.9	$ 269.3	$ 132.8	$ 138.3	$ 544.9	$ 1,061.6	$ 1,517.6	$ 866.5	$ 666.2
Operating expense	17.7	18.0	3.5	24.1	11.5	12.0	15.3	24.4	49.1	23.8	23.9
Depreciation and amortization expense	12.2	11.3	9.2	56.0	27.4	28.5	10.4	23.1	70.0	34.1	35.7
General and administrative expense	7.2	7.3	1.1	6.9	3.2	3.5	11.1	16.8	16.1	5.3	8.0
Interest expense allocated from parent	—	—	11.5	72.9	35.7	—	6.1	9.6	—	43.1	—
Interest expense, net	—	—	—	—	—	17.7	—	—	48.6	—	24.3
Loss on debt extinguishment	—	—	—	—	—	—	—	15.2	—	—	—
Deferred income taxes(1)	—	—	—	2.5	1.5	0.7	—	—	2.9	1.9	0.7
Other, net	0.3	—	—	—	—	—	—	—	—	—	(0.3)
Net income (loss)	$ 38.6	$ 45.9	$ (5.1)	(46.9)	$ (23.2)	$ (0.7)	$ 16.1	9.7	$ 51.0	$ 11.3	$ 2.9
Pro forma net income per limited partner unit									$ 1.13		$ 0.06

	Predecessor Business					Targa Resources Partners LP	Targa Resources Partners LP Pro Forma				
	Dynegy		Targa North Texas LP								
	Year Ended December 31, 2004	Ten Months Ended October 31, 2005	Two Months Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007	Period from March 12, 2004 to December 31, 2004	Year Ended December 31, 2005	Year Ended December 31, 2006	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007
	(Audited)	(Audited)	(Audited)	(Audited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
	(In millions of dollars, except per unit, operating and price data)										
Financial and Operating Data:											
Financial data:											
Operating margin(2)	$ 58.3	$ 64.5	$ 16.7	$ 91.4	$ 44.6	$ 49.7	$ 43.7	$ 74.4	$ 188.6	$ 95.7	$ 71.3
Adjusted EBITDA(3)	50.8	57.2	15.6	84.5	41.4	46.2	31.3	54.4	155.8	82.0	84.6
Operating data:											
Gathering throughput, MMcf/d(4)	152.0	161.2	168.8	168.3	167.3	166.3					
Plant Natural Gas Inlet, MMcf/d(5)	145.4	156.2	161.9	161.8	160.4	160.0					
Gross NGL production, MBbl/d	17.2	18.5	19.8	18.9	18.7	17.3					
Natural gas sales, BBtu/d	59.2	68.9	72.3	74.9	74.4	75.9					
NGL sales, MBbl/d	13.2	14.3	15.4	15.2	13.9	13.0					
Condensate sales, MBbl/d	0.7	0.5	0.5	0.5	1.6	1.9					
Average Realized Prices:											
Natural gas, $/MMBtu	$ 5.43	$ 6.79	$ 8.61	$ 6.09	$ 6.28	$ 6.84					
NGL, $/gal	0.64	0.78	0.90	0.88	0.84	0.87					
Condensate, $/Bbl	40.56	53.42	57.54	65.31	51.87	52.97					
Balance Sheet Data (at period end):											
Property, plant, and equipment, net	$ 191.2	$ 196.4	$ 1,097.0	$ 1,064.1	$ 1,080.8	$ 1,046.1					$ 1,276.3
Total assets	193.5	198.5	1,122.8	1,115.8	1,116.8	1,123.8					1,421.0
Long-term debt including current portion	—	—	868.9	864.0	866.4	294.5					673.4
Partners' capital /Net parent investment	168.8	158.5	219.5	215.6	220.4	767.7					571.1
Cash Flow Data:											
Net cash provided by (used in):											
Operating activities	$ 58.0	$ 72.7	$ (1.5)	$ 16.2	$ 3.4	$ 23.5					
Investing activities	(23.4)	(16.4)	(2.1)	(23.1)	(11.2)	(10.5)					
Financing activities	(34.6)	(56.3)	3.6	6.9	7.8	(3.6)					

(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. 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."

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

(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 point of a natural gas processing plant.

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 learnings 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 measures, understanding the differences between the measures and incorporating these learnings 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.

	Predecessor Business: Dynegy Year Ended December 31, 2004 (Audited)	Predecessor Business: Dynegy Ten Months Ended October 31, 2005 (Audited)	Predecessor Business: Targa North Texas LP Two Months Ended December 31, 2005 (Audited)	Predecessor Business: Targa North Texas LP Year Ended December 31, 2006 (Audited)	Predecessor Business: Targa North Texas LP Six Months Ended June 30, 2006 (Unaudited)	Targa Resources Partners LP Six Months Ended June 30, 2007 (Unaudited)	Targa Resources Partners LP Pro Forma Period from March 12, 2004 to December 31, 2004 (Unaudited)	Targa Resources Partners LP Pro Forma Year Ended December 31, 2005 (Unaudited)	Targa Resources Partners LP Pro Forma Year Ended December 31, 2006 (Unaudited)	Targa Resources Partners LP Pro Forma Six Months Ended June 30, 2006 (Unaudited)	Targa Resources Partners LP Pro Forma Six Months Ended June 30, 2007 (Unaudited)
						(In millions)					
Reconciliation of "Adjusted EBITDA" to net cash provided by (used in) operating activities:											
Net cash provided by (used in) operating activities	$ 58.0	$ 72.7	$ (1.5)	$ 16.2	$ 3.4	$ 23.5					
Allocated interest expense from parent(1)	—	—	10.7	67.8	33.1	—					
Interest expense, net(1)	—	—	—	—	—	17.4					
Changes in operating working capital which provided (used) cash:											
Accounts receivable	(0.7)	0.3	0.1	(0.2)	(0.4)	11.7					
Accounts payable	(2.7)	1.3	0.8	(0.6)	6.8	(6.6)					
Other, including changes in noncurrent assets and liabilities	(3.8)	(17.1)	5.5	1.3	(1.5)	0.2					
Non-cash mark-to-market loss (gain)	—	—	—	—	—	—					
Adjusted EBITDA	$ 50.8	$ 57.2	$ 15.6	$ 84.5	$ 41.4	$ 46.2					
Reconciliation of "Adjusted EBITDA" to net income:											
Net income (loss)	$ 38.6	$ 45.9	$ (5.1)	$ (46.9)	$ (23.2)	$ (0.7)	$ 16.1	$ 9.7	$ 51.0	$ 11.3	$ 2.9
Add:											
Allocated interest expense from parent	—	—	11.5	72.9	35.7	—	6.1	9.6	—	43.1	—
Interest expense, net	—	—	—	—	—	17.7	—	—	48.6	—	24.3
Deferred tax expense	—	—	—	2.5	1.5	0.7	—	—	2.9	1.9	0.7
Depreciation and amortization expense	12.2	11.3	9.2	56.0	27.4	28.5	10.4	23.1	70.0	34.1	35.7
Non-cash mark-to-market loss (gain)	—	—	—	—	—	—	(1.3)	12.0	(16.7)	(8.4)	21.0
Adjusted EBITDA	$ 50.8	$ 57.2	$ 15.6	$ 84.5	$ 41.4	$ 46.2	$ 31.3	$ 54.4	$ 155.8	$ 82.0	$ 84.6
Reconciliation of "operating margin" to net income:											
Net income (loss)	$ 38.6	$ 45.9	$ (5.1)	$ (46.9)	$ (23.2)	$ (0.7)	$ 16.1	$ 9.7	$ 51.0	$ 11.3	$ 2.9
Add:											
Depreciation and amortization expense	12.2	11.3	9.2	56.0	27.4	28.5	10.4	23.1	70.0	34.1	35.7
Deferred income tax	—	—	—	2.5	1.5	0.7	—	—	2.9	1.9	0.7
Other, net	0.3	—	—	—	—	—	—	—	—	—	(0.3)
Loss on debt extinguishment	—	—	—	—	—	—	—	15.2	—	—	—
Allocated interest expense from parent	—	—	11.5	72.9	35.7	—	6.1	9.6	—	43.1	—
Interest expense, net	—	—	—	—	—	17.7	—	—	48.6	—	24.3
General and administrative expense	7.2	7.3	1.1	6.9	3.2	3.5	11.1	16.8	16.1	5.3	8.0
Operating margin	$ 58.3	$ 64.5	$ 16.7	$ 91.4	$ 44.6	$ 49.7	$ 43.7	$ 74.4	$ 188.6	$ 95.7	$ 71.3

(1) Excludes non-cash amortization of debt issue costs of $0.8 million for the two months ended December 31, 2005, $5.1 million for the year ended December 31, 2006, $2.6 million for the six months ended June 30, 2006 and $0.3 million for the six months ended June 30, 2007.

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 consistent with those that would be faced by a corporation engaged in similar businesses. You should consider carefully the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units.

If any of the following risks were actually to occur, then our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment.

The following risks are presented as if we have completed the acquisition of the Acquired Businesses.

Risks Related to Our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to make cash distributions to holders of our common units and subordinated units at the minimum quarterly distribution rate under our cash distribution policy.

In order to make our cash distributions at our minimum quarterly distribution rate of $0.3375 per common unit and subordinated unit per complete quarter, or $1.35 per unit per year, we will require available cash of approximately $15.3 million per quarter, or $61.1 million per year, based on our common units and subordinated units outstanding immediately upon completion of this offering ($16.0 million or $63.9 million, respectively, if the underwriters exercise in full their option to purchase additional common units). We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at the minimum quarterly 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 natural gas liquids, or 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 amended 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.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, please see "Our Cash Distribution Policy."

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

Our operations can be affected by the level of natural gas and NGL prices and the relationship between these prices. The prices of natural gas and NGLs have been volatile and we expect this volatility to continue. The NYMEX daily settlement price for natural gas for the prompt month contract in the year ended December 31, 2005 ranged from a high of $15.38 per MMBtu to a low of $5.79 per MMBtu and for the year ended December 31, 2006 ranged from a high of $10.63 per MMBtu to a low of $4.20 per MMBtu. From the beginning of 2007 through June 30, 2007 the NYMEX daily settlement price for natural gas has ranged from a high of $9.07 per MMBtu to a low of $5.40 per MMBtu. NGL prices exhibit similar volatility. Based on monthly index prices, the average price for our NGL composition in the year ended December 31, 2005 ranged from a high of $1.12 per gallon to a low of $0.73 per gallon and for the year ended December 31, 2006 ranged from a high of $1.18 per gallon to a low of $0.92 per gallon in 2006. From the beginning of 2007 through June 30, 2007 the average price for our NGL composition ranged from a high of $1.13 per gallon to a low of $0.93 per gallon.

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, 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 six month period ended June 30, 2007, our percent-of-proceeds arrangements accounted for approximately 82% 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.

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 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. 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. We believe that rig availability in the areas in which we operate has been and will continue to be a limiting factor on the number of wells drilled in these areas. 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. Natural gas prices reached historic highs in 2005 and early 2006, but declined substantially in the second half of 2006 and have continued to decline in 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.

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 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, NGL and condensate prices that we realize in our operations. These pricing differentials may be substantial and 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 “Management’s

Discussion and Analysis of Financial Condition and Results of Operation — 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 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 years ended December 31, 2006 and 2005 was ConocoPhillips, who accounted for approximately 12.5% and 13.3%, respectively, of our supply. The loss of all or even a portion of the natural gas volumes supplied by this customer 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 and cash available for distribution 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 system 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 the Acquired Businesses, especially the Mertzon, Sterling and Gillis plants and their respective gathering systems.

Any significant curtailment of gathering, compressing, treating, processing or fractionation of natural gas on our Chico system or at our other plants and systems 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, 2006, our Chico plant inlet volume accounted for over 31% of our revenues. Operations at our Chico system or our other plants or systems 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 deductions. If a significant accident or event occurs at our Chico system 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.

We will use the proceeds of this offering together with borrowings to purchase the Acquired Businesses. If the Acquired Businesses or future acquisitions do not perform as expected, our future financial performance may be negatively impacted.

Our acquisition of the Acquired Businesses will significantly increase the size of our company and diversify the geographic areas in which we operate. We cannot assure you that we will achieve the desired profitability from the Acquired Businesses or any other acquisitions we may complete in the future. In addition, failure to successfully 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 operation 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 Acquired Businesses' natural gas for a term of 15 years and NGLs for a term of one year. Targa also manages the Acquired Businesses' natural gas sales to third parties under contracts that remain in the name of the Acquired Businesses. 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. 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. 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.

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 six months ended June 30, 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.

Upon completion of this offering, we expect to have approximately $673.4 million of debt 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 will 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 will make 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 will depend 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 “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Requirements.”

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. Upon completion of this offering, we expect to have approximately $673.4 million of debt outstanding under our amended credit facility at variable interest rates. An increase of 1 percentage point in the interest rates will result in an increase in annual interest expense of $6.7 million. As a result, our results of operations, cash flows and financial condition could be materially adversely affected by significant increases in interest rates.

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 upon 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 5.75 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.

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 natural gas gathering, treating, fractionating and processing 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. 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, or 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, or 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 wastes have been transported for disposal, and (4) the Federal Water Pollution Control Act, also know as 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 and property damage 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 "Business — Environmental Matters" for more information.

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 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, financial condition and our ability to make cash distributions to you.

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.

Our natural gas gathering and transportation operations are generally exempt from Federal Energy Regulatory Commission, or FERC, regulation under the Natural Gas Act of 1938, or NGA, but FERC regulation still affects those businesses and the markets for products derived from those businesses. FERC has recently proposed to require intrastate pipelines, possibly including natural gas gathering pipelines, to comply with certain Internet posting requirements, with the goal of promoting transparency in the interstate natural gas market. FERC has not yet issued a final rule on that proposed rulemaking. We may experience an increase in costs if the rule is adopted as proposed.

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.

Section 1(b) of the Natural Gas Act of 1938, or 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. Accordingly, in such a circumstance, the classification and regulation of some of our natural gas gathering facilities and intrastate transportation pipelines may be subject to change based on future determinations by FERC, the courts, or Congress.

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, or EPAct 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.

State regulation of natural gas gathering facilities and intrastate transportation pipelines generally includes various safety, environmental and, in some circumstances, nondiscriminatory take and common purchaser requirements, and complaint-based rate regulation. 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 as a number of such companies have transferred gathering facilities to unregulated affiliates. The states we operate in have adopted regulations that generally allow natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering and intrastate transportation pipeline access and rate discrimination. Our gathering and intrastate transportation operations could be adversely affected in the future should they become subject to the application of state or federal regulation of rates and services. These operations may also be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of such facilities. Other state regulations may not directly apply to our business, but may nonetheless affect the availability of natural gas for purchase, processing and sale, including state regulation of production rates and maximum daily production allowable from natural gas wells. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect our business. For more information regarding regulation of Targa's operations, please read "Business — Regulation of Operations."

Under the terms of our gas sales agreement, Targa will manage the sales of our natural gas and will pay us the amount it realizes for gas sales less certain costs; however, 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 Acquired Businesses' natural gas sales to third parties under contracts that remain in the name of the Acquired Businesses. 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, the United States Department of Transportation, or DOT, 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 $1 million between 2007 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.

Our historical and pro forma financial information may not be representative of our results as a combined company.

The historical and pro forma financial information included in this prospectus is derived from our separate financial statements, the separate financial statements of Targa for periods prior to our initial public offering, the separate financial statements of Dynegy Midstream Services, Limited Partnership ("DMS") for periods prior to the consummation of Targa's acquisition of DMS and the separate financial statements of Targa's predecessor for periods prior to the consummation of Targa's acquisition of the Acquired Businesses. The audited historical financial statements of the Predecessor Business and the Acquired Businesses were prepared in accordance with GAAP, on a going-concern basis, as if the Predecessor Business and the Acquired

Businesses had existed as separate entities during the periods presented. Expenses included in the financial statements of the Predecessor business and the Acquired Businesses may not be indicative of the level of expenses that might have been incurred had such businesses been operating as separate stand-alone companies. In addition, the unaudited pro forma financial information presented in this prospectus is based, in part, on certain assumptions regarding our acquisition of the Acquired Businesses that we believe are reasonable. To the extent financial statements are prepared for our business in the future, such information will differ from the information contained herein, and such differences may be material.

Accordingly, the historical, pro forma and other financial information included in this prospectus may not reflect what our results of operations and financial condition would have been had we been a combined entity during the periods presented, or what our results of operations and financial condition will be in the future.

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, involves 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 the 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 own all 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.

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 develop or 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

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; please see "— Targa is not limited in its ability to compete with us, which could limit our ability to acquire additional assets or businesses" below.

Please see "Conflicts of Interest and Fiduciary Duties."

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 will 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 will not be 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 will be 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.

If you purchase any common units, you will agree to become bound by the provisions in the partnership agreement, including the provisions discussed above. Please see “Conflicts of Interests and Fiduciary Duties — Fiduciary Duties.”

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 prohibit 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. Please see “Conflicts of Interest and Fiduciary Duties.”

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 Resources GP LLC, our general partner and others, 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 “Certain Relationships and Related Transactions — Omnibus Agreement.” 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 our 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 our 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 our common units.

Management of our general partner and Targa beneficially hold 85,700 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 our 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. Please see "Our Cash Distribution Policy — General Partner Interest and 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 our 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 our 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 26.0% of our aggregate outstanding common units. For additional information about this right, please see "The Partnership Agreement — Limited Call Right."

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.

For a discussion of the implications of the limitations of liability on a unitholder, please see "The Partnership Agreement — Limited Liability."

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

In addition to reading the following risk factors, you should read "Material Tax Consequences" for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

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 IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our 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. For example, 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. 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, beginning in 2008, we will be required to pay Texas margin 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 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, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders. Please read "Material Tax Consequences — Disposition of Common Units — Allocations Between Transferors and Transferees."

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS 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 conclusions of our counsel expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or 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 will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read "Material Tax Consequences — Disposition of Common Units — Recognition of Gain or Loss" for a further discussion of the foregoing.

Tax-exempt entities and non-U.S. 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 employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations 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-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file 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-U.S. person, you should consult your tax advisor before investing in our common units.

We treat each purchaser of 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 our common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. 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 your 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. Please read "Material Tax Consequences — Tax Consequences of Unit Ownership — Section 754 Election" for a further discussion of the effect of the depreciation and amortization positions we adopted.

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 could result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one fiscal year. Our termination could also 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. Please read "Material Tax Consequences — Disposition of Common Units — Constructive Termination" for a discussion of the consequences of our termination for federal income tax purposes.

You will likely be subject to state and local taxes and return filing requirements in states 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 Texas and Louisiana. Currently, Texas does not impose a personal income tax on individuals but Louisiana does. Moreover, both states impose entity level taxes on corporations and other entities. 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, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

USE OF PROCEEDS

We expect the acquisition of the Acquired Businesses to close concurrently with this offering of common units and that in connection with that closing our credit facility will be amended.

We expect to receive net proceeds from this offering of approximately $348.2 million, after deducting underwriting discounts but before estimated offering expenses. We also expect to borrow approximately $378.9 million under our amended credit facility.

We intend to use the net proceeds of this offering of common units and borrowings under our amended credit facility to pay approximately:

- $697.6 million of the $705.0 million aggregate consideration, subject to certain adjustments, to Targa to acquire the Acquired Businesses;
- $24.2 million to Targa for certain hedge transactions associated with the Acquired Businesses effected on September 25 and 26, 2007 which is an adjustment to the purchase price for the Acquired Businesses; and
- $5.3 million of estimated expenses associated with our acquisition of the Acquired Businesses and the related financing transactions, including this offering of common units.

In addition, we will issue to our general partner 275,511 general partner units as partial consideration for the Acquired Businesses, enabling it to maintain its 2% general partner interest in us.

We entered into a $500 million revolving credit facility in February 2007 and simultaneously drew down a revolving loan thereunder, the proceeds of which (together with approximately $371.2 million of net proceeds from our initial public offering) were used to repay approximately $665.7 million of affiliate indebtedness. We intend to use the increased borrowing capacity from our amended credit facility to partially fund the acquisition of the Acquired Businesses from Targa. Borrowings under our revolving credit facility bear interest at the higher of the lender's prime rate or the federal funds rate plus 0.5% (plus an applicable margin based on the Partnership's total leverage ratio), or LIBOR (plus an applicable margin based on the Partnership's total leverage ratio). As of September 28, 2007, we had $294.5 million of outstanding indebtedness under our revolving credit facility, which matures in 2012, at an interest rate of 6.7%. If the underwriters exercise their option to purchase additional common units, we will use the net proceeds to reduce outstanding borrowings under our amended credit facility.

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CAPITALIZATION

The following table shows:

- our historical cash and capitalization as of June 30, 2007; and
- our pro forma cash and capitalization to reflect the sale of common units in this offering, borrowings under our amended credit facility and the application of the net proceeds therefrom as described under "Use of Proceeds."

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical and pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations." For a description of the pro forma adjustments, please see our Unaudited Pro Forma Condensed Balance Sheet.

	As of June 30, 2007	
	Historical	Pro Forma
	(In millions)	
Cash	$ 9.4	$ 9.4
Long-term debt:		
Credit facility	294.5	673.4
Partners' capital(1)(2)		
Common units — public	378.2	724.4
Subordinated units — sponsor(3)	376.7	(133.5)
General partner interest(3)(4)	20.6	(12.1)
Total partners' capital	775.5	578.8
Total capitalization	$ 1,070.0	$ 1,252.2

(1) Partners' capital excludes accumulated other comprehensive income.

(2) This table does not reflect the issuance of up to 2,025,000 common units that may be sold to the underwriters upon exercise of their option to purchase additional units.

(3) Our acquisition of the Acquired Businesses in connection with this offering is accounted for and presented under common control accounting. Under common control accounting, the Acquired Businesses' assets and liabilities are recorded at their book value with the balance of the acquisition proceeds recorded as an adjustment to parent equity. The adjustment to parent equity of $550.3 million has been allocated $510.2 million and $40.1 million to the subordinated unitholder and general partner capital accounts, respectively, in proportion to Targa's ownership of us prior to this offering. As a result, after giving effect to our acquisition of the Acquired Businesses and this offering, the subordinated unitholder and general partner book basis capital account balances will be $(133.5) million and $(12.1) million, respectively.

(4) We will issue to our general partner 275,511 general partner units as partial consideration for the Acquired Businesses, enabling it to maintain its 2% general partner interest in us.

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

Our common units are listed and traded on The NASDAQ Stock Market LLC under the symbol "NGLS." Our common units began trading on February 9, 2007 at an initial public offering price of $21.00 per common unit. The following table shows the low and high sales prices per common unit, as reported by The NASDAQ Stock Market LLC, for the periods indicated. Distributions are shown in the quarter for which they were paid.

	Low	High	Cash Distribution per Unit
2007:			
First quarter(1)	$22.75	$29.30	$ 0.16875(2)
Second quarter	27.70	35.28	0.3375(3)
Third quarter	24.39	35.00	
Fourth quarter(4)	25.10	29.36	

(1) February 9, 2007, the day our common units began trading on The NASDAQ Stock Market LLC, through March 31, 2007.

(2) Reflects the pro rata portion of the $0.3375 quarterly distribution per unit paid, representing the period from the February 14, 2007 closing of our initial public offering through March 31, 2007. An identical cash distribution was paid on all outstanding common and subordinated units.

(3) An identical cash distribution was paid on all outstanding common and subordinated units.

(4) Through October 18, 2007.

The last reported sale price of our common units on The NASDAQ Stock Market LLC on October 18, 2007 was $26.87. As of October 17, 2007, there were approximately 11 holders of record of our common units.

CASH DISTRIBUTION POLICY

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.

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 distributions 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 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. We will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default is existing, under our credit agreement. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Capital Requirements — Description of Credit Agreement" for a discussion of the restrictions to be included in our credit agreement that may restrict our ability to make distributions.

General Partner Interest and Incentive Distribution Rights. Our general partner is currently entitled to 2% of all quarterly distributions that we make prior to our liquidation. Our 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 may be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute from operating surplus (as defined below) in excess of $0.3881 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 subordinated units that it owns. Please see " — General Partner Interest and Incentive Distribution Rights" for additional information.

Operating Surplus and Capital Surplus

General. All cash distributed to unitholders will be characterized as either "operating surplus" or "capital surplus." Our partnership agreement requires that we distribute available cash from operating surplus differently than available cash from capital surplus.

Operating Surplus. Operating surplus consists of:

- an amount equal to four times the amount needed for any one quarter for us to pay a distribution on all of our units (including the general partner units) and the incentive distribution rights at the same per-unit amount as was distributed in the immediately preceding quarter; plus
- all of our cash receipts, excluding cash from borrowings, sales of equity and debt securities, sales or other dispositions of assets outside the ordinary course of business, capital contributions or corporate

reorganizations or restructurings (provided that cash receipts from the termination of a commodity hedge or interest rate swap prior to its specified termination date shall be included in operating surplus in equal quarterly installments over the scheduled life of such commodity hedge or interest rate swap); less

- all of our operating expenditures, but excluding the repayment of borrowings, and including maintenance capital expenditures; less
- the amount of cash reserves established by our general partner to provide funds for future operating expenditures.

Maintenance capital expenditures represent capital expenditures made to replace partially or fully depreciated assets, to maintain the existing operating capacity of our assets and to extend their useful lives, or other capital expenditures that are incurred in maintaining existing system volumes and related cash flows. Expansion capital expenditures represent capital expenditures made to expand or to increase the efficiency of the existing operating capacity of our assets or to expand the operating capacity or revenues of existing or new assets, whether through construction or acquisition. Costs for repairs and minor renewals to maintain facilities in operating condition and that do not extend the useful life of existing assets will be treated as operating expenses as we incur them. Our partnership agreement provides that our general partner determines how to allocate a capital expenditure for the acquisition or expansion of our assets between maintenance capital expenditures and expansion capital expenditures.

Capital Surplus. Capital surplus generally consists of:

- borrowings;
- sales of our equity and debt securities;
- sales or other dispositions of assets for cash, other than inventory, accounts receivable and other current assets sold in the ordinary course of business or as part of normal retirement or replacement of assets;
- capital contributions received; and
- corporate restructurings.

Characterization of Cash Distributions. Our partnership agreement requires that we treat all available cash distributed as coming from operating surplus until the sum of all available cash distributed since we began operations equals the operating surplus as of the most recent date of determination of available cash. Our partnership agreement requires that we treat any amount distributed in excess of operating surplus, regardless of its source, as capital surplus. As reflected above, operating surplus includes an amount equal to four times the amount needed for any one quarter for us to pay a distribution on all of our units (including the general partner units) and the incentive distribution rights at the same per-unit amount as was distributed in the immediately preceding quarter. This amount does not reflect actual cash on hand that is available for distribution to our unitholders. Rather, it is a provision that will enable us, if we choose, to distribute as operating surplus up to this amount of cash we receive in the future from non-operating sources, such as asset sales, issuances of securities, and borrowings, that would otherwise be distributed as capital surplus. We do not anticipate that we will make any distributions from capital surplus.

Subordination Period

General. Our partnership agreement provides that, during the subordination period (which we define below), our common units have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on our common units from prior quarters, before any distributions of available cash from operating surplus 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 are not entitled to receive any distributions until our 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 our common units.

Subordination Period. The subordination period will extend until the first day of any quarter beginning after March 31, 2010 that each of the following tests are met:

- distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and general partner units equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;
- the "adjusted operating surplus" (as defined below) generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common and subordinated units and general partner units during those periods on a fully diluted basis during those periods; and
- there are no arrearages in payment of the minimum quarterly distribution on our common units.

Expiration of the Subordination Period. When the subordination period expires, each outstanding subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and units held by the general partner and its affiliates are not voted in favor of such removal:

- the subordination period will end and each subordinated unit will immediately convert into one common unit;
- any existing arrearages in payment of the minimum quarterly distribution on our common units will be extinguished; and
- the general partner will have the right to convert its general partner units and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Early Conversion of Subordinated Units. The subordination period will automatically terminate and all of the subordinated units will convert into common units on a one-for-one basis if each of the following occurs:

- distributions of available cash from operating surplus on each outstanding common unit and subordinated unit equaled or exceeded 150% of the annualized minimum quarterly distribution for any four-quarter period immediately preceding that date;
- the "adjusted operating surplus" (as defined below) generated during any four-quarter period immediately preceding that date equaled or exceeded the sum of a distribution of 150% of the annualized minimum quarterly distribution on all of the outstanding common units and subordinated units and general partner units on a fully diluted basis; and
- there are no arrearages in payment of the minimum quarterly distribution on our common units.

Adjusted Operating Surplus. Adjusted operating surplus is intended to reflect the cash generated from operations during a particular period and therefore excludes net drawdowns of reserves of cash generated in prior periods. Adjusted operating surplus consists of:

- operating surplus generated with respect to that period (excluding any amounts attributable to the items described in the first bullet point under "— Operating Surplus and Capital Surplus — Operating Surplus" above); plus
- any net decrease made in subsequent periods in cash reserves for operating expenditures initially established with respect to that period to the extent such decrease results in a reduction in adjusted operating surplus in subsequent periods pursuant to the following bullet point; less
- any net decrease in cash reserves for operating expenditures with respect to that period not relating to an operating expenditure made with respect to that period; plus

- any net increase in cash reserves for operating expenditures with respect to that period required by any debt instrument for the repayment of principal, interest or premium.

Distributions of Available Cash from Operating Surplus during the Subordination Period

Our 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 our 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; and
- *thereafter*, in the manner described in "— General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2% general partner interest and that we do not issue additional classes of equity securities.

Distributions of Available Cash from Operating Surplus after the Subordination Period

Our 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 we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter*, in the manner described in "— General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our general partner maintains its 2% general partner interest and that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our general partner is entitled to 2% of all distributions that we make prior to our liquidation as long as our general partner maintains its current 2% interest in us. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2% general partner interest if we issue additional units. Our general partner's 2% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us in order to maintain its 2% general partner interest. Our general partner will be entitled to make a capital contribution in order to maintain its 2% general partner interest in the form of the contribution to us of common units that it may hold based on the current market value of the contributed common units.

Incentive distribution rights represent the right to receive an increasing percentage (13%, 23% and 48%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

The following discussion assumes that the general partner maintains its 2% general partner interest and continues to own the incentive distribution rights.

If for any quarter:

- we have distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and
- we have distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner 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 (the "first target distribution");
- *second*, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives a total of $0.4219 per unit for that quarter (the "second target distribution");
- *third*, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives a total of $0.50625 per unit for that quarter (the "third target distribution"); and
- *thereafter*, 50% to all unitholders, pro rata, and 50% to the general partner.

Percentage Allocations of Available Cash from Operating Surplus

The following table illustrates the percentage allocations of available cash from operating surplus between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our general partner and the unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit," until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for the unitholders and the general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2% general partner interest and assume our general partner has contributed any additional capital to maintain its 2% general partner interest and has not transferred its incentive distribution rights.

	Total Quarterly Distribution per Unit	Marginal Percentage Interest in Distributions	
	Target Amount	Unitholders	General Partner
Minimum Quarterly Distribution	$0.3375	98%	2%
First Target Distribution	up to $0.3881	98%	2%
Second Target Distribution	above $0.3881 up to $0.4219	85%	15%
Third Target Distribution	above $0.4219 up to $0.50625	75%	25%
Thereafter	above $0.50625	50%	50%

General Partner's Right to Reset Incentive Distribution Levels

Our general partner, as the holder of our incentive distribution rights, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. Our general partner's right to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are based may be exercised, without approval of our unitholders or the conflicts committee of our general partner, at any time when there are no subordinated units outstanding and we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for each of the prior four consecutive fiscal quarters. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that our general partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per unit following this event increase as described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to our general partner.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target cash distributions prior to the reset, our general partner will be entitled to receive a number of newly issued Class B units based on a predetermined formula described below that takes into account the “cash parity” value of the average cash distributions related to the incentive distribution rights received by our general partner for the two quarters prior to the reset event as compared to the average cash distributions per common unit during this period.

The number of Class B units that our general partner would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to (x) the average amount of cash distributions received by our general partner in respect of its incentive distribution rights during the two consecutive fiscal quarters ended immediately prior to the date of such reset election divided by (y) the average of the amount of cash distributed per common unit during each of these two quarters. Each Class B unit will be convertible into one common unit at the election of the holder of the Class B unit at any time following the first anniversary of the issuance of these Class B units. We will also issue an additional amount of general partner units in order to maintain the general partner’s ownership interest in us relative to the issuance of the Class B units.

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 be correspondingly higher such that we would distribute all of our available cash from operating surplus for each quarter thereafter as follows:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives an amount equal to 115% of the reset minimum quarterly distribution for that quarter;
- *second*, 85% to all unitholders, pro rata, and 15% to the general partner, until each unitholder receives an amount per unit equal to 125% of the reset minimum quarterly distribution for that quarter;
- *third*, 75% to all unitholders, pro rata, and 25% to the general partner, until each unitholder receives an amount per unit equal to 150% of the reset minimum quarterly distribution for that quarter; and
- *thereafter*, 50% to all unitholders, pro rata, and 50% to the general partner.

Distributions from Capital Surplus

How Distributions from Capital Surplus Will Be Made. Our partnership agreement requires that we make distributions of available cash from capital surplus, if any, in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until we distribute for each common unit an amount of available cash from capital surplus equal to the initial public offering price;
- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on our common units; and
- *thereafter*, we will make all distributions of available cash from capital surplus as if they were from operating surplus.

Effect of a Distribution from Capital Surplus. Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from the initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per unit is referred to as the "unrecovered initial unit price." Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution, after any of these distributions are made, it may be easier for the general partner to receive incentive distributions and for the subordinated units to convert into common units. However, any distribution of capital surplus before the unrecovered initial unit price is reduced to zero cannot be applied to the payment of the minimum quarterly distribution or any arrearages.

Once we distribute capital surplus on a unit in an amount equal to the initial unit price, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels will be reduced to zero. Our partnership agreement specifies that we then make all future distributions from operating surplus, with 50% being paid to the holders of units and 50% to the general partner. The percentage interests shown for our general partner include its 2% general partner interest and assume the general partner has not transferred the incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our units into fewer units or subdivide our units into a greater number of units, our partnership agreement specifies that the following items will be proportionately adjusted:

- the minimum quarterly distribution;
- target distribution levels;
- the unrecovered initial unit price; and
- the number of common units into which a subordinated unit is convertible.

For example, if a two-for-one split of our common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50% of its initial level, and each subordinated unit would be convertible into two common units. Our partnership agreement provides that we not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a governmental taxing authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, our partnership agreement specifies that the general partner may reduce the minimum quarterly distribution and the target distribution levels for each quarter by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter and the denominator of which is the sum of available cash for that quarter plus the general partner's estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Distributions of Cash Upon Liquidation

General. If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on our common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of the general partner.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will allocate any gain to the partners in the following manner:

- *first*, to the general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;
- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;
- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner until the capital account for each subordinated unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;
- *fourth*, 98% to all unitholders, pro rata, and 2% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the minimum quarterly distribution per unit that we distributed 98% to the unitholders, pro rata, and 2% to the general partner, for each quarter of our existence;
- *fifth*, 85% to all unitholders, pro rata, and 15% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the first target distribution per unit that we distributed 85% to the unitholders, pro rata, and 15% to the general partner for each quarter of our existence;
- *sixth*, 75% to all unitholders, pro rata, and 25% to the general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the third target distribution per unit over the second target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from operating surplus in excess of the second target distribution per unit that we distributed 75% to the unitholders, pro rata, and 25% to the general partner for each quarter of our existence; and
- *thereafter*, 50% to all unitholders, pro rata, and 50% to the general partner.

The percentage interests set forth above for our general partner include its 2% general partner interest and assume the general partner has not transferred the incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

Manner of Adjustments for Losses. If our liquidation occurs before the end of the subordination period, we will generally allocate any loss to the general partner and the unitholders in the following manner:

- *first*, 98% to holders of subordinated units in proportion to the positive balances in their capital accounts and 2% to the general partner, until the capital accounts of the subordinated unitholders have been reduced to zero;

- *second*, 98% to the holders of common units in proportion to the positive balances in their capital accounts and 2% to the general partner, until the capital accounts of the common unitholders have been reduced to zero; and
- *thereafter*, 100% to the general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

Adjustments to Capital Accounts. Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the general partner in the same manner as we allocate gain or loss upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the general partner's capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made.

SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The following table shows summary historical financial and operating data of Targa Resources Partners LP and the Predecessor Business and pro forma financial data of Targa Resources Partners LP for the periods and as of the dates indicated. We refer to the assets, liabilities and operations of the North Texas System contributed to us by Targa upon the closing of our initial public offering as the Predecessor Business. The Predecessor Business was acquired by Targa as part of the DMS Acquisition. The summary historical financial data of the Predecessor Business as of and for the years ended December 31, 2002, 2003 and 2004, the ten-month period ended October 31, 2005, the two-month period ended December 31, 2005 and the year ended December 31, 2006 are derived from the audited financial statements of the Predecessor Business. The summary historical financial data of the Predecessor Business as of and for the six months ended June 30, 2006 are derived from the unaudited financial statements of the Predecessor Business. The summary historical financial data as of and for the six months ended June 30, 2007 are derived from the unaudited financial statements of Targa Resources Partners LP.

The summary pro forma financial data for the period from March 12, 2004 to December 31, 2004, the years ended December 31, 2005 and 2006, the six months ended June 30, 2006 and 2007 and as of June 30, 2007 are derived from the unaudited pro forma financial statements of Targa Resources Partners LP included in this prospectus. The pro forma statements of operations for the year ended December 31, 2006 and for the six months ended June 30, 2007 have been prepared as if certain transactions effected at the closing of our initial public offering, the acquisition of the Acquired Businesses and this offering had taken place on January 1, 2006. The pro forma balance sheet as of June 30, 2007 has been prepared as if the acquisition of the Acquired Businesses and this offering had taken place on June 30, 2007. The Targa entities which purchased the Acquired Businesses were formed by Targa on March 12, 2004 and the results of operations of the Acquired Businesses are reflected in our pro forma financial statements from and after April 16, 2004, the date of Targa's acquisition of the Acquired Businesses from ConocoPhillips. The pro forma financial information for the period from March 12, 2004 to December 31, 2004, the year ended December 31, 2005, and the six months ended June 30, 2006 reflect the combined results of operations of the Predecessor Business and the Acquired Businesses for all periods when such businesses were under the common controlling ownership of Targa. Targa Resources Partners LP and the Acquired Businesses are controlled by a common parent entity, Targa. The acquisition of the Acquired Businesses by Targa Resources Partners LP is accounted for and presented under common control accounting. Under common control accounting, the Acquired Businesses' assets and liabilities are recorded at their book value with the balance of acquisition proceeds recorded as an adjustment to parent equity.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the historical combined and pro forma condensed financial statements and the accompanying notes beginning on page F-3.

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	Predecessor Business							Targa Resources Partners LP	Targa Resources Partners LP Pro Forma				
	Dynegy				Targa North Texas LP								
	Year Ended December 31,			Ten Months Ended October 31,	Two Months Ended December 31,	Year Ended December 31,	Six Months Ended June 30,	Six Months Ended June 30,	Period from March 12, 2004 to December 31,	Year Ended December 31,		Six Months Ended June 30,	
	2002	2003	2004	2005	2005	2006	2006	2007	2004	2005	2006	2006	2007
	(Unaudited)	(Audited)	(Audited)	(Audited)	(Audited)	(Audited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)	(Unaudited)
	(In millions of dollars, except operating and price data)												
Statement of Operations Data:													
Total operating revenues	$ 112.5	$ 196.8	$ 258.6	$ 293.3	$ 75.1	$ 384.8	$ 188.9	$ 200.0	$ 603.9	$ 1,160.4	$ 1,755.3	$ 986.0	$ 761.4
Product purchases	$ 82.7	$ 147.3	$ 182.6	$ 210.8	$ 54.9	$ 269.3	$ 132.8	$ 138.3	$ 544.9	$ 1,061.6	$ 1,517.6	$ 866.5	$ 666.2
Operating expense	14.9	15.1	17.7	18.0	3.5	24.1	11.5	12.0	15.3	24.4	49.1	23.8	23.9
Depreciation and amortization expense	11.8	12.0	12.2	11.3	9.2	56.0	27.4	28.5	10.4	23.1	70.0	34.1	35.7
General and administrative expense	7.7	7.7	7.2	7.3	1.1	6.9	3.2	3.5	11.1	16.8	16.1	5.3	8.0
Interest expense allocated from parent	—	—	—	—	11.5	72.9	35.7	—	6.1	9.6	—	43.1	—
Interest expense, net	—	—	—	—	—	—		17.7	—	—	48.6	—	24.3
Loss on debt extinguishment	—	—	—	—	—	—	—	—	—	15.2	—	—	—
Deferred income taxes(1)	—	—	—	—	—	2.5	1.5	0.7	—	—	2.9	1.9	0.7
Other, net	(0.3)	0.6	0.3	—	—	—	—	—	—	—	—	—	(0.3)
Net income (loss)	$ (4.3)	$ 14.1	$ 38.6	$ 45.9	$ (5.1)	$ (46.9)	$ (23.2)	$ (0.7)	$ 16.1	$ 9.7	$ 51.0	$ 11.3	$ 2.9
Pro forma net income (loss) per limited partner unit											$ 1.13		$ 0.06
Financial and Operating Data:													
Financial data:													
Operating margin(2)	$ 14.9	$ 34.4	$ 58.3	$ 64.5	$ 16.7	$ 91.4	$ 44.6	$ 49.7	$ 43.7	$ 74.4	$ 188.6	$ 95.7	$ 71.3
Adjusted EBITDA(3)	7.5	26.1	50.8	57.2	15.6	84.5	41.4	46.2	31.3	54.4	155.8	82.0	84.6
Operating data:													
Gathering throughput, MMcf/d(4)	106.6	134.3	152.0	161.2	168.8	168.3	167.3	166.3					
Plant natural gas inlet, MMcf/d(5)	104.0	128.6	145.4	156.2	161.9	161.8	160.4	160.0					
Gross NGL production, MBbl/d	12.5	15.9	17.2	18.5	19.8	18.9	18.7	17.3					
Natural gas sales, BBtu/d	38.2	42.0	59.2	68.9	72.3	74.9	74.4	75.9					
NGL sales, MBbl/d	12.3	15.3	13.2	14.3	15.4	15.2	13.9	13.0					
Condensate sales, MBbl/d	0.6	0.6	0.7	0.5	0.5	0.5	1.6	1.9					
Average Realized Prices:													
Natural gas, $/MMBtu	$ 2.84	$ 4.97	$ 5.43	$ 6.79	$ 8.61	$ 6.09	$ 6.28	$ 6.84					
NGL, $/gal	0.35	0.47	0.64	0.78	0.90	0.88	0.84	0.87					
Condensate, $/Bbl	23.24	29.86	40.56	53.42	57.54	65.31	51.87	52.97					
Balance Sheet Data (at period end):													
Property, plant, and equipment, net	$ 178.2	$ 180.4	$ 191.2	$ 196.4	$ 1,097.0	$ 1,064.1	$ 1,080.8	1,046.1					$ 1,276.3
Total assets	179.7	182.9	193.5	198.5	1,122.8	1,115.8	1,116.8	1,123.8					1,421.0
Long-term debt (including current portion)	—	—	—	—	868.9	864.0	866.4	294.5					673.4
Partners' capital /Net parent investment	167.3	164.8	168.8	158.5	219.5	215.6	220.4	767.7					571.1
Cash Flow Data:													
Net cash provided by (used in):													
Operating activities	$ 10.2	$ 31.3	$ 58.0	$ 72.7	$ (1.5)	$ 16.2	$ 3.4	$ 23.5					
Investing activities	(30.6)	(14.6)	(23.4)	(16.4)	(2.1)	(23.1)	(11.2)	(10.5)					
Financing activities	20.4	(16.7)	(34.6)	(56.3)	3.6	6.9	7.8	(3.6)					

(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. The amount presented represents our estimated liability for this tax.

(2) 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 learnings 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 measures, understanding the differences between the measures and incorporating these learnings 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.

	Predecessor Business: Dynegy: Years Ended December 31, 2002 (Unaudited)	Predecessor Business: Dynegy: Years Ended December 31, 2003 (Audited)	Predecessor Business: Dynegy: Years Ended December 31, 2004 (Audited)	Predecessor Business: Dynegy: Ten Months Ended October 31, 2005 (Audited)	Predecessor Business: Targa North Texas LP: Two Months Ended December 31, 2005 (Audited)	Predecessor Business: Targa North Texas LP: Year Ended December 31, 2006 (Audited)	Predecessor Business: Targa North Texas LP: Six Months Ended June 30, 2006 (Unaudited) (In millions)	Targa Resources Partners LP: Six Months Ended June 30, 2007 (Unaudited)	Targa Resources Partners LP Pro Forma: Period from March 12, 2004 to December 31, 2004 (Unaudited)	Targa Resources Partners LP Pro Forma: Year Ended December 31, 2005 (Unaudited)	Targa Resources Partners LP Pro Forma: Year Ended December 31, 2006 (Unaudited)	Targa Resources Partners LP Pro Forma: Six Months Ended June 30, 2006 (Unaudited)	Targa Resources Partners LP Pro Forma: Six Months Ended June 30, 2007 (Unaudited)
Reconciliation of "Adjusted EBITDA" to net cash provided by (used in) operating activities:													
Net cash provided by (used in) operating activities	$ 10.2	$ 31.3	$ 58.0	$ 72.7	$ (1.5)	$ 16.2	$ 3.4	$ 23.5					
Allocated interest expense from parent(a)	—	—	—	—	10.7	67.8	33.1	—					
Interest expense, net(a)	—	—	—	—	—	—	—	17.4					
Changes in operating working capital which provided (used) cash:													
Accounts receivable	0.3	0.7	(0.7)	0.3	0.1	(0.2)	(0.4)	11.7					
Accounts payable	0.6	(1.0)	(2.7)	1.3	0.8	(0.6)	6.8	(6.6)					
Other, including changes in noncurrent assets and liabilities	(3.6)	(4.9)	(3.8)	(17.1)	5.5	1.3	(1.5)	0.2					
Non-cash mark-to-market loss (gain)	—	—	—	—	—	—	—	—					
Adjusted EBITDA	$ 7.5	$ 26.1	$ 50.8	$ 57.2	$ 15.6	$ 84.5	$ 41.4	$ 46.2					
Reconciliation of "Adjusted EBITDA" to net income:													
Net income (loss)	$ (4.3)	$ 14.1	$ 38.6	$ 45.9	$ (5.1)	$ (46.9)	$ (23.2)	$ (0.7)	$ 16.1	$ 9.7	$ 51.0	$ 11.3	$ 2.9
Add:													
Allocated interest expense from parent	—	—	—	—	11.5	72.9	35.7	—	6.1	9.6	—	43.1	—
Interest expense, net	—	—	—	—	—	—	—	17.7	—	—	48.6	—	24.3
Deferred tax expense	—	—	—	—	—	2.5	1.5	0.7	—	—	2.9	1.9	0.7
Depreciation and amortization expense	11.8	12.0	12.2	11.3	9.2	56.0	27.4	28.5	10.4	23.1	70.0	34.1	35.7
Non-cash mark-to-market loss (gain)	—	—	—	—	—	—	—	—	(1.3)	12.0	(16.7)	(8.4)	21.0
Adjusted EBITDA	$ 7.5	$ 26.1	$ 50.8	$ 57.2	$ 15.6	$ 84.5	$ 41.4	$ 46.2	$ 31.3	$ 54.4	$ 155.8	$ 82.0	$ 84.6
Reconciliation of "operating margin" to net income:													
Net income (loss)	$ (4.3)	$ 14.1	$ 38.6	$ 45.9	$ (5.1)	$ (46.9)	$ (23.2)	$ (0.7)	$ 16.1	$ 9.7	$ 51.0	$ 11.3	$ 2.9
Add:													
Depreciation and amortization expense	11.8	12.0	12.2	11.3	9.2	56.0	27.4	28.5	10.4	23.1	70.0	34.1	35.7
Deferred income tax	—	—	—	—	—	2.5	1.5	0.7	—	—	2.9	1.9	0.7
Other, net	(0.3)	0.6	0.3	—	—	—	—	—	—	—	—	—	(0.3)
Loss on debt extinguishment	—	—	—	—	—	—	—	—	—	15.2	—	—	—
Allocated interest expense from parent	—	—	—	—	11.5	72.9	35.7	—	6.1	9.6	—	43.1	—
Interest expense, net	—	—	—	—	—	—	—	17.7	—	—	48.6	—	24.3
General and administrative expense	7.7	7.7	7.2	7.3	1.1	6.9	3.2	3.5	11.1	16.8	16.1	5.3	8.0
Operating margin	$ 14.9	$ 34.4	$ 58.3	$ 64.5	$ 16.7	$ 91.4	$ 44.6	$ 49.7	$ 43.7	$ 74.4	$ 188.6	$ 95.7	$ 71.3

(a) Excludes non-cash amortization of debt issue costs of $0.8 million for the two months ended December 31, 2005, $5.1 million for the year ended December 31, 2006, $2.6 million for the six months ended June 30, 2006 and $0.3 million for the six months ended June 30, 2007.

(3) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization, and non-cash income or loss related to derivative instruments.

(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.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

On February 14, 2007, we completed our initial public offering, or IPO, of common units. In the IPO, we issued 19,320,000 common units (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) at a price of $21.00 per unit. We used the net proceeds of the IPO to pay expenses related to the IPO and our credit facility and to repay approximately $371.2 million of our outstanding affiliate indebtedness. Upon completion of the IPO, we had 19,320,000 common units, 11,528,231 subordinated units, and 629,555 general partner units outstanding. The subordinated units and general partner units are indirectly owned by Targa Resources, Inc.

The historical financial statements included in this item reflect the results of operations of the North Texas System contributed to us by Targa at the time of the IPO. We refer to the results of operations of the North Texas System as the results of operations of the Predecessor Business. The Predecessor Business was acquired by Targa as part of Targa's acquisition of substantially all of Dynegy Inc.'s midstream business on October 31, 2005 (the "DMS Acquisition").

The following discussion analyzes the financial condition and results of operations of the Predecessor Business. In the discussion, the year ended December 31, 2005 is generally presented and evaluated on a combined basis, combining the results of operations reflected in the audited historical financial statements of the Predecessor Business for the 10-months prior to the DMS Acquisition (the "Pre-Acquisition Financial Statements") and the results of operations reflected in the audited historical financial statements of the Predecessor Business for the two-months after the DMS Acquisition (the "Post-Acquisition Financial Statements"). In certain circumstances, our discussion identifies distinctions in operating and financial results for the Predecessor Business associated with the change of ownership resulting from the DMS Acquisition. You should read the following discussion of the financial condition and results of operations for the Predecessor Business and the pro forma financial statements for Targa Resources Partners LP included elsewhere in this prospectus.

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). In certain circumstances and for ease of reading we discuss the financial results of the Predecessor Business as being "our" financial results during historic periods when this business was owned by Dynegy or Targa, respectively.

Overview

We are a Delaware limited partnership formed by Targa to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. On February 14, 2007, Targa contributed to us the entities holding the North Texas System. The North Texas System consists of two wholly-owned natural gas processing plants and an extensive network of integrated gathering pipelines that serve a 14-county natural gas producing region in the Fort Worth Basin in north Texas, which is one of the most active natural gas basins in the U.S. as measured by drilling activity. This producing region includes production from the Barnett Shale formation and production from shallower formations including the Bend Conglomerate, Caddo, Atoka, Marble Falls, and other Pennsylvanian and upper Mississippian formations (referred to as the "other Fort Worth Basin formations"). The natural gas processing plants consist of the Chico processing and fractionation facilities and the Shackelford processing facility.

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 (representing approximately 97% of our gathered natural gas volumes for the six months ended June 30, 2007) and keep-whole contracts (representing approximately 3% of our gathered natural gas volumes for the six months ended June 30, 2007), each of which exposes us to commodity price risk. We attempt to mitigate this risk through hedging activities which can materially impact our results of operations. Please see “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 “Business — Midstream Sector Overview.”

Upon the closing of our IPO, Targa contributed to us the assets, liabilities and operations reflected in the historical financial statements. The historical financial statements of the Partnership 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. At December 31, 2006, affiliate indebtedness consisted of borrowings incurred by Targa and allocated to us for financial reporting purposes. A substantial portion of Targa’s October 31, 2005 acquisition of Dynegy Inc.’s interest in Dynegy Midstream Services, Limited Partnership (the “DMS Acquisition”) was financed through borrowings. A significant portion of Targa’s acquisition borrowings were allocated to the Partnership which initially resulted in approximately $870.1 million of allocated indebtedness. Targa North Texas LP, the entity holding the North Texas System, provided a guarantee of the indebtedness. The indebtedness was also secured by a collateral interest in both the equity of Targa North Texas LP as well as its assets.

On January 1, 2007 the allocated debt was extinguished through a deemed capital contribution by Targa and affiliate indebtedness of $904.5 million (including accrued interest of $88.3 million) related to the North Texas System was contributed to us.

On February 14, 2007, we borrowed $342.5 million under our credit facility and concurrently repaid $48.0 million under our credit facility with 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 issuance costs and necessary operating cash reserves balances) were used to repay $665.7 million of affiliate indebtedness. Immediately before closing of the IPO, the remaining affiliate indebtedness in excess of $665.7 million was retired through a capital contribution to us. In connection with the IPO, our guarantee of Targa’s indebtedness was terminated and the collateral interest was released.

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, NGL and condensate equity volumes for the years 2007 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 “Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk.”

General and Administrative Expenses. The Predecessor Business recognized general and administrative expenses as a result of allocations from the consolidated general and administrative expenses of Dynegy and Targa, respectively. Allocated general and administrative expenses were $6.9 million, $8.4 million and

$7.2 million for the years ended December 31, 2006, 2005 and 2004, respectively. On February 14, 2007, the Partnership entered into an omnibus agreement with Targa pursuant to which our allocated general and administrative expenses are capped at $5.0 million per year for three years, subject to adjustment. For a more complete description of this agreement, see “Certain Relationships and Related Transactions — Omnibus Agreement.” In addition to these allocated general and administrative expenses, we expect to 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 are expected to be approximately $2.5 million annually, are not subject to the cap contained in the omnibus agreement and 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 Predecessor Businesses.

Working Capital Adjustments. In the historical financial statements of the Predecessor Businesses, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with the Predecessor Businesses’ 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 Businesses 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 Businesses does not reflect any affiliate accounts receivable for intercompany commodity sales or affiliate accounts payable for the personnel and services provided by or paid for by the applicable parent on behalf of the Predecessor Businesses.

Distributions to our Unitholders. We intend to make cash distributions to our unitholders and our general partner at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs. Historically, the North Texas System has largely 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 approved by the Board of Directors of our general partner on April 23, 2007 and paid on May 15, 2007 to unitholders of record as of the close of the business on May 3, 2007. For the second quarter of 2007, a distribution to unitholders of $0.3375 per common unit was approved by the Board of Directors of our general partner on July 23, 2007 and paid on August 14, 2007 to unitholders of record as of the close of business on August 2, 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 2006, the prices we realized for natural gas declined to an average of $5.96 per MMBtu from an average of $7.11 per MMBtu for 2005. For 2005, the prices we realized for natural gas rose from an average of $5.43 per MMBtu for 2004. In part as a result of the prevailing prices during these periods, the Fort Worth Basin has experienced significant levels of drilling activity, providing us with opportunities to access newly developed natural gas supplies. Our largest supplier of natural gas in the Fort Worth Basin is ConocoPhillips, which represented approximately 33% and 36% of the natural gas supplied to our system for the years ended December 31, 2006 and 2005, respectively. We believe that current natural gas prices will continue to cause relatively high levels of natural gas-related drilling in the Fort Worth Basin/Bend Arch 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 the year ended December 31, 2006, excluding the impact of hedging activities, we sold an average of 74.9 BBtu/d of residue gas at an average price of $5.96 per MMBtu, as compared to 69.5 BBtu/d at an average price of $7.11 per MMBtu for the year ended December 31, 2005, and 59.2 BBtu/d at an average price of $5.43 per MMBtu for the year ended December 31, 2004. For the year ended December 31, 2006, we sold an average of 15.2 MBbl/d of NGLs at an average price of $36.98 per Bbl, as compared to 14.5 MBbl/d at an average price of $33.57 per Bbl for the year ended December 31, 2005, and 13.2 MBbl/d at an average price of $26.71 per Bbl for the year ended December 31, 2004. Additionally, we separately sold condensate during these periods. 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 "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, both in the Fort Worth Basin and more broadly across the United States, is 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 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. Under these types of arrangements, our revenues correlate directly with the price of natural gas and NGLs. For the six months ended June 30, 2007, our percent-of-proceeds activities accounted for approximately 97% of our natural gas throughput volumes. The balance of our throughput volumes are processed under wellhead purchases and keep-whole contractual arrangements.

Our Chico facility includes an NGL fractionator with the capacity to fractionate up to approximately 11,500 Bbl/d of the raw NGL mix that results from the processing of natural gas at Chico. This fractionation capability allows Chico to deliver either raw NGL mix to Mont Belvieu primarily through Chevron's WTLPG Pipeline or separated NGL products to local and other markets via truck.

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, see "Certain Relationships and Related Transactions" and "Business — Market Access — Chico System Market Access."

The Acquired Businesses

We will acquire the Acquired Businesses from Targa for aggregate consideration of $705 million, subject to certain adjustments, concurrently with the closing of this offering. This will increase our miles of natural gas gathering pipelines and our processing capacity by approximately 50% and 140%, respectively, and is expected to provide us with significant additional throughput volumes and cash flow.

On September 25 and 26, 2007, Targa completed transactions to terminate certain out of the money NGL hedges associated with the Acquired Businesses and to enter into new hedges for approximately the same volume and term at then current market prices. Pursuant to the purchase and sale agreement for the Acquired Businesses, these transactions will result in a $24.2 million increase to the purchase price we will pay to Targa for the Acquired Businesses. The difference in price between the original hedges and the new hedges results in an increase in the cash settlement for the hedged volumes of approximately $2.6 million for the period November through December, 2007, and of approximately $11.7 million, $9.0 million, $2.0 million and $0.3 million for years 2008 through 2011, respectively.

The Acquired Businesses have been managed with systems, practices and personnel consistent with ours, maintain a similar reputation and customer base and provide a similar package of midstream services. The SAOU System operates primarily under percent-of-proceeds contracts and the LOU System operates primarily under percent-of-proceeds and short-term wellhead purchase contracts. After giving effect to the acquisition of the Acquired Businesses, our aggregate contract profile for the first half of 2007 would be approximately 82% percent-of-proceeds, approximately 1% fee and approximately 17% wellhead purchase/keep whole contracts, on a volume basis. 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. The commodity risk exposure of the Acquired Businesses has been managed similarly to the North Texas System and we expect that the combined businesses will be managed to hedge the commodity price exposure associated with a significant portion of expected equity volumes of natural gas and NGLs in the near to mid-term. General and administrative costs for the Acquired Businesses will be consistent with the historical methodology for charging direct, indirect and allocated costs associated with the Acquired Businesses. The existing cap on certain general and administrative costs for the North Texas System will remain in place. We believe that the financing for the acquisition of the Acquired Businesses provides a capital structure that will support the organic growth opportunities in the North Texas System and the Acquired Businesses and provide commercial liquidity and support for the combined businesses. Please see "Business — Our Systems," "— Liquidity and Capital Resources — Description of Credit Agreement" and "— Summary of Our Hedges" for more information about the Acquired Businesses, our amended credit facility and our commodity hedging activities, respectively.

Our results of operations presented below do not include results of operations of the Acquired Businesses.

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 NGL 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 learnings 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. 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 learnings into management's decision-making processes.

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 learnings into our decision making processes.

	Targa Resources Partners LP	Predecessor Business					
		Targa North Texas LP			Combined	Dynegy	
	Six Months Ended June 30, 2007 (Unaudited)	Six Months Ended June 30, 2006 (Unaudited)	Year Ended December 31, 2006 (Audited)	Two Months Ended December 31, 2005 (Audited)	Year Ended December 31, 2005 (Unaudited)	Ten Months Ended October 31, 2005 (Audited)	Year Ended December 31, 2004 (Audited)
	(In millions of dollars)						
Net income (loss)	$ (0.7)	$ (23.2)	$ (46.9)	$ (5.1)	$ 40.8	$ 45.9	$ 38.6
Depreciation and amortization expense	28.5	27.4	56.0	9.2	20.5	11.3	12.2
Deferred tax expense	0.7	1.5	2.5	—	—	—	—
Amortization of debt issue costs	0.3	2.6	5.1	0.8	0.8	—	—
Maintenance capital expenditures	(5.3)	(6.3)	(11.7)	(1.6)	(12.9)	(11.3)	(10.2)
Distributable cash flows(a)	$ 23.5	$ 2.0	$ 5.0	$ 3.3	$ 49.2	$ 45.9	$ 40.6

(a) Distributable cash flow for the year ended December 31, 2006, the six months ended June 30, 2006 and the two months ended December 31, 2005, reflects allocated interest from parent of $72.9 million, $35.7 million and $11.5 million, respectively.

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 our revenues are generated under percent-of-proceeds arrangements pursuant to which 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. Please see 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 based on volumes for the six months ended June 30, 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	97%	Decreases in natural gas and/or NGL prices generate decreases in operating margins.
Wellhead Purchases/Keep Whole	3%	Increases in natural gas prices relative to NGL prices generate decreases in operating margins. Decreases in NGL prices relative to natural gas prices generate decreases in operating margins.

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.

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Results of Operations

The following table and discussion is a summary of our results of operations for the six months ended June 30, 2007 and 2006 and the three years ended December 31, 2006.

	Targa Resources Partners LP	Predecessor Business					
		Targa North Texas LP			Combined	Dynegy	
	Six Months Ended June 30, 2007 (Unaudited)	Six Months Ended June 30, 2006 (Unaudited)	Year Ended December 31, 2006 (Audited)	Two Months Ended December 31, 2005 (Audited)	Year Ended December 31, 2005 (Unaudited)	Ten Months Ended October 31, 2005 (Audited)	Year Ended December 31, 2004 (Audited)
	(In millions of dollars, except operating and price data)						
Total operating revenues	$ 200.0	$ 188.9	$ 384.8	$ 75.1	$ 368.4	$ 293.3	$ 258.6
Product purchases	138.3	132.8	269.3	54.9	265.7	210.8	182.6
Operating expense, excluding DD&A	12.0	11.5	24.1	3.5	21.5	18.0	17.7
Depreciation and amortization expense	28.5	27.4	56.0	9.2	20.5	11.3	12.2
General and administrative expense	3.5	3.2	6.9	1.1	8.4	7.3	7.2
Income from operations	17.7	14.0	28.5	6.4	52.3	45.9	38.9
Interest expense allocated from parent	—	35.7	72.9	11.5	11.5	—	—
Interest expense, net	17.7	—	—	—	—	—	—
Deferred income taxes(1)	0.7	1.5	2.5	—	—	—	—
Other, net	—	—	—	—	—	—	0.3
Net income (loss)	$ (0.7)	$ (23.2)	$ (46.9)	$ (5.1)	$ 40.8	$ 45.9	$ 38.6
Financial data:							
Operating margin(2)	$ 49.7	$ 44.6	$ 91.4	$ 16.7	$ 81.2	$ 64.5	$ 58.3
Adjusted EBITDA(3)	46.2	41.4	$ 84.5	$ 15.6	$ 72.8	$ 57.2	$ 50.8
Operating data:							
Gathering throughput, MMcf/d(4)(4)	166.3	167.3	168.3	168.8	162.5	161.2	152.0
Plant Natural Gas Inlet, MMcf/d(5)	160.0	160.4	161.8	161.9	157.2	156.2	145.4
Gross NGL production, MBbl/d	17.3	18.7	18.9	19.8	18.7	18.5	17.2
Natural gas sales, BBtu/d	75.9	74.4	74.9	72.3	69.5	68.9	59.2
NGL sales, MBbl/d	13.0	13.9	15.2	15.4	14.5	14.3	13.2
Condensate sales, MBbl/d	1.9	1.6	0.5	0.5	0.5	0.5	0.7
Average Realized Prices:							
Natural gas, $/MMBtu	$ 6.84	$ 6.28	$ 6.09	$ 8.61	$ 7.11	$ 6.79	$ 5.43
NGL, $/gal	0.87	0.84	0.88	0.90	0.80	0.78	0.64
Condensate, $/Bbl	52.97	51.87	65.31	57.54	54.03	53.42	40.56

(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. 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."

(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."

(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.

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 learnings 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 learnings into management's decision-making processes.

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

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

	Targa Resources Partners LP	Predecessor Business				
		Targa North Texas LP			Dynegy	
	Six Months Ended June 30, 2007 (Unaudited)	Six Months Ended June 30, 2006 (Unaudited)	Year Ended December 31, 2006 (Audited)	Two Months Ended December 31, 2005 (Audited)	Ten Months Ended October 31, 2005 (Audited)	Year Ended December 31, 2004 (Audited)
	(In millions)					
Reconciliation of "Adjusted EBITDA" to net cash provided by (used in) operating activities:						
Net cash provided by (used in) operating activities	$ 23.5	$ 3.4	$ 16.2	$ (1.5)	$ 72.7	$ 58.0
Allocated interest expense from parent(1)	—	33.1	67.8	10.7	—	—
Interest expense, net(1)	17.4	—	—	—	—	—
Changes in operating working capital which provided (used) cash:						
Accounts receivable	11.7	(0.4)	(0.2)	0.1	0.3	(0.7)
Accounts payable	(6.6)	6.8	(0.6)	0.8	1.3	(2.7)
Other, including changes in noncurrent assets and liabilities	0.2	(1.5)	1.3	5.5	(17.1)	(3.8)
Non-cash mark-to-market loss (gain)	—	—	—	—	—	—
Adjusted EBITDA	$ 46.2	$ 41.4	$ 84.5	$ 15.6	$ 57.2	$ 50.8
Reconciliation of "Adjusted EBITDA" to net income:						
Net income (loss)	$ (0.7)	$ (23.2)	$ (46.9)	$ (5.1)	$ 45.9	$ 38.6
Add:						
Interest expense allocated from parent	—	35.7	72.9	11.5	—	—
Interest expense, net	17.7	—	—	—	—	—
Deferred tax expense	0.7	1.5	2.5	—	—	—
Depreciation and amortization expense	28.5	27.4	56.0	9.2	11.3	12.2
Non-cash mark-to-market loss (gain)	—	—	—	—	—	—
Adjusted EBITDA	$ 46.2	$ 41.4	$ 84.5	$ 15.6	$ 57.2	$ 50.8

	Targa Resources Partners LP	Predecessor Business				
		Targa North Texas LP			Dynegy	
	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(Unaudited)	(Unaudited)	(Audited)	(Audited)	(Audited)	(Audited)
	(In millions)					
Reconciliation of "operating margin" to net income:						
Net income (loss)	$ (0.7)	$ (23.2)	$ (46.9)	$ (5.1)	$ 45.9	$ 38.6
Add:						
Depreciation and amortization expense	28.5	27.4	56.0	9.2	11.3	12.2
Deferred income tax	0.7	1.5	2.5	—	—	—
Other, net	—	—	—	—	—	0.3
Loss on debt extinguishment	—	—	—	—	—	—
Interest expense allocated from parent	—	35.7	72.9	11.5	—	—
Interest expense, net	17.7	—	—	—	—	—
General and administrative expense	3.5	3.2	6.9	1.1	7.3	7.2
Operating margin	$ 49.7	$ 44.6	$ 91.4	$ 16.7	$ 64.5	$ 58.3

(1) Excludes non-cash amortization of debt issue costs of $0.3 million for the six months ended June 30, 2007, $2.6 million for the six months ended June 30, 2006, $5.1 million for the year ended December 31, 2006, and $0.8 million for the two months ended December 31, 2005.

Comparison of Six Months Ended June 30, 2007 to Six Months Ended June 30, 2006

Total Operating Revenues. Our revenues increased $11.1 million, or 6%, to $200.0 million for the six months ended June 30, 2007 compared to $188.9 million for the six months ended June 30, 2006. The increase is primarily due to:

- a net decrease attributable to commodity sales volume of $1.3 million, consisting of increases in natural gas and condensate revenues of $1.7 million and $2.7 million, respectively, offset by a decrease in NGL revenues of $5.7 million.
- an increase attributable to commodity prices of $11.1 million, consisting of increases in natural gas, NGL and condensate revenues of $7.7 million, $3.0 million and $0.4 million, respectively.
- an increase in revenues from fee based processing activities of $1.3 million.

Average realized prices for natural gas increased by $0.56 per MMBtu (including a $0.38 increase related to hedging), or 9%, to $6.84 per MMBtu for the six months ended June 30, 2007 compared to $6.28 per MMBtu for the six months ended June 30, 2006. The average realized price for NGL increased by $0.03 per gallon (net of a $0.01 decrease related to hedging), or 4%, to $0.87 per gallon for the six months ended June 30, 2007 compared to $0.84 per gallon for the six months ended June 30, 2006. The average realized price for condensate increased by $1.10 per Bbl (including a $2.58 increase related to hedging), or 2%, to $52.97 per Bbl for the six months ended June 30, 2007 compared to $51.87 per Bbl for the six months ended June 30, 2006.

Natural gas sales volumes increased by 1.5 BBtu/d, or 2%, to 75.9 BBtu/d for the six months ended June 30, 2007 compared to 74.4 BBtu/d for the six months ended June 30, 2006. Volumes for the six months ended June 30, 2007 were also negatively impacted by unseasonable wet weather which limited our ability to complete connections to new wells. NGL sales volumes decreased by 0.9 MBbl/d, or 6%, to 13.0 MBbl/d for the six months ended June 30, 2007 compared to 13.9 MBbl/d for the six months ended June 30, 2006. Some of the new production connected to the Chico plant increased the average carbon dioxide ("CO_2") content, requiring the plant to expand the CO_2 treating capabilities by putting an existing CO_2 treater back into operation. The treater had to be refurbished, and was not operational until April 2007. Until that time, the plant rejected ethane to allow the increased CO_2 to pass through the plant into the residue gas to keep the NGL product on specification. For the six months ended June 30, 2007, these changes in operations resulted in decreased NGL recoveries compared to the six months ended June 30, 2006. Condensate sales volumes increased by 0.3 MBbl/d, or 19%, to 1.9 MBbl/d for the six months ended June 30, 2007 compared to 1.6 MBbl/d for the six months ended June 30, 2006.

Product Purchases. Product purchases increased by $5.5 million, or 4%, to $138.3 million for the six months ended June 30, 2007 compared to $132.8 million for the six months ended June 30, 2006. For the six months ended June 30, 2007 and 2006, product purchases were 69% and 70% of total revenues, respectively. The increase in product purchases for the six months ended June 30, 2007 corresponds with the increase in revenues for the same period.

Operating Expenses. Operating expenses increased by $0.5 million, or 4%, to $12.0 million for the six months ended June 30, 2007 compared to $11.5 million for the six months ended June 30, 2006.

Depreciation and Amortization. Depreciation and amortization expense increased by $1.1 million, or 4%, to $28.5 million for the six months ended June 30, 2007 compared to $27.4 million for the six months ended June 30, 2006. The increase is due to the higher carrying value of property, plant and equipment as a result of capital spending in the last six months of 2006 and the first six months of 2007.

General and Administrative. General and administrative expense increased by $0.3 million, or 9%, to $3.5 million for the six months ended June 30, 2007 compared to $3.2 million for the six months ended June 30, 2006. For the period from February 14, 2007 through June 30, 2007, general and administrative expenses were limited by the $5 million annual cap on general and administrative expense under the Omnibus Agreement. For this period, our general and administrative expense allocation was approximately $1.9 million. For additional information regarding our allocation of general and administrative costs, please see “Certain Relationships and Related Transactions — Omnibus Agreement.”

Interest Expense. Interest expense recorded for the six months ended June 30, 2007 was $17.7 million, which reflects pre-IPO interest expense of $9.8 million on debt contributed to us for the period from January 1, 2007 though February 13, 2007 and $7.9 million in interest expense for the period from February 14, 2007 through June 30, 2007, reflecting the interest costs associated with borrowings under our revolving credit facility. The decrease in interest expense for the six months ended June 30, 2007 of $18.0 million, or 50%, from $35.7 million for the six months ended June 30, 2006 is due to the repayment of affiliate indebtedness with the proceeds of our IPO offset by borrowings under our credit facility.

Income Taxes. The Partnership is not subject to Federal income taxes. As a result, the earnings or losses for federal income tax purposes are includable in the tax returns of the individual partners. In May 2006, Texas adopted a margin tax consisting of a 1% tax on the amount by which total revenues exceed cost of goods. Accordingly, we have estimated our liability for this tax.

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

Our results of operations for the year ended December 31, 2006 were prepared on the same basis as the Post-Acquisition Financial Statements. The combined results of operations for the Predecessor Business for the year ended December 31, 2005 are unaudited and do not necessarily represent the results that would have been achieved during this period had the business been operated by Targa for the entire year. Our results of operations for the two months ended December 31, 2005 were prepared on the same basis as the financial statements for the year ended December 31, 2006. Our results of operations for the ten months ended December 31, 2005 were prepared on the same basis as the Pre-Acquisition Financial Statements. Because different bases of accounting were followed in the preparation of these results of operations, the reported results of operations for the years ended December 31, 2005 and 2006 are not necessarily comparable. The primary differences include debt and interest expense allocations, depreciation and amortization, and general and administrative expense allocations. The results of operations and related analyses for the Predecessor Business for the year ended December 31, 2005 do not necessarily represent the results that would have been achieved during this period had the business been operated by Targa for the entire year. The combined financial information for the year ended December 31, 2005 is not in accordance with GAAP, but is presented for the convenience of investors to facilitate the presentation of a more meaningful discussion of the historical periods.

Total Operating Revenues. Revenues increased by $16.4 million, or 4%, to $384.8 million (including $4.6 million of net hedge settlements) for the year ended December 31, 2006 compared to $368.4 million (no hedge settlements) for the year ended December 31, 2005. This increase was primarily due to the following factors:

- a net decrease attributable to commodity prices of $6.2 million, consisting of increases in NGL and condensate revenue of $19.4 million and $2.2 million, respectively, offset by a decrease in natural gas revenue of $27.8 million; and
- a net increase attributable to volumes of $22.6 million, consisting of increases in natural gas, NGL and condensate revenue of $14.0 million, $8.5 million and $0.1 million, respectively.

Average realized prices for natural gas decreased by $1.02 per MMBtu, or 14%, to $6.09 per MMBtu ($0.13 per MMBtu related to hedge settlements) for the year ended December 31, 2006 compared to $7.11 per MMBtu for the year ended December 31, 2005. The average realized price for NGLs increased by $0.08 per gallon, or 10%, to $0.88 per gallon for the year ended December 31, 2006 compared to $0.80 per gallon for the year ended December 31, 2005. The average realized price for condensate increased by $11.28 per Bbl, or 21%, to $65.31 per Bbl ($3.75 per Bbl related to hedge settlements) for the year ended December 31, 2006 compared to $54.03 per Bbl for the year ended December 31, 2005.

Natural gas sales volumes increased by 5.4 BBtu/d, or 8%, to 74.9 BBtu/d for the year ended December 31, 2006 compared to 69.5 BBtu/d for the year ended December 31, 2005. NGL sales volumes increased by 0.7 MBbl/d, or 5%, to 15.2 MBbl/d for the year ended December 31, 2006 compared to 14.5 MBbl/d for the year ended December 31, 2005. Condensate volumes were flat with no change between the periods. The increases in both natural gas and NGL sales volumes were primarily due to higher field production as a result of new well connections.

Product Purchases. Product purchases increased by $3.6 million, or 1%, to $269.3 million for the year ended December 31, 2006 compared to $265.7 million for the year ended December 31, 2005. Increased volumes accounted for $17.4 million of this increase, offset by $13.8 million due to lower commodity prices.

Operating Expenses. Operating expenses increased by $2.6 million, or 12%, to $24.1 million for the year ended December 31, 2006 compared to $21.5 million for the year ended December 31, 2005. The increase was driven by higher costs in 2006 compared to 2005 for labor, supplies and equipment incurred in the expansion of our gathering system as well as increased costs for these services.

Depreciation and Amortization. Depreciation and amortization expense increased by $35.5 million, or 173%, to $56.0 million for the year ended December 31, 2006 compared to $20.5 million for the year ended December 31, 2005. The increase is due to the higher carrying value of property, plant and equipment as a result of the DMS Acquisition.

General and Administrative. General and administrative expense decreased by $1.5 million, or 18%, to $6.9 million for the year ended December 31, 2006 compared to $8.4 million for the year ended December 31, 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 the year ended December 31, 2006 was $72.9 million compared to $11.5 million for the year ended December 31, 2005. Interest expense recorded for the year ended December 31, 2006 reflects an allocation of debt and related interest expense incurred by Targa in connection with the DMS Acquisition. Prior to the DMS Acquisition, there was no allocation of debt or interest expense to the Predecessor Business.

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

Our results of operations for the year ended December 31, 2005 are derived from the combination of the results of operations reflected in the Pre-Acquisition Financial Statements and the results of operations reflected in the Post-Acquisition Financial Statements. The combined results of operations for the Predecessor Business for the year ended December 31, 2005 are unaudited and do not necessarily represent the results that would have been achieved during this period had the business been operated by Targa for the entire year. The combined financial information for the year ended December 31, 2005 is not in accordance with GAAP, but is presented for the convenience of investors to facilitate the presentation of a more meaningful discussion of the historical periods.

Total Operating Revenues. Combined revenues increased by $109.8 million, or 42%, to $368.4 million for the year ended December 31, 2005 compared to $258.6 million for the year ended December 31, 2004. This increase was primarily due to the following factors:

- an increase attributable to commodity prices of $81.3 million, consisting of increases in natural gas, NGL and condensate revenue of $42.6 million, $36.2 million and $2.5 million, respectively;
- a net increase attributable to volumes of $29.2 million, consisting of increases in natural gas and NGL revenue of $19.9 million and $11.8 million, respectively, partially offset by a decrease in condensate revenue of $2.5 million; and
- partially offset by a decrease in fee and other revenues of $0.7 million.

Average realized prices for natural gas increased by $1.68 per MMBtu, or 31%, to $7.11 per MMBtu for the year ended December 31, 2005 compared to $5.43 per MMBtu for the year ended December 31, 2004. The average realized price for NGL increased by $0.16 per gallon, or 25%, to $0.80 per gallon for the year ended December 31, 2005 compared to $0.64 per gallon for the year ended December 31, 2004. The average realized price for condensate increased by $13.47 per Bbl, or 33%, to $54.03 per Bbl for the year ended December 31, 2005 compared to $40.56 per Bbl for the year ended December 31, 2004.

Natural gas sales volume increased by 10.3 BBtu/d, or 17%, to 69.5 BBtu/d for the year ended December 31, 2005 compared to 59.2 BBtu/d for the year ended December 31, 2004. Net NGL production increased by 1.3 MBbl/d, or 10%, to 14.5 MBbl/d for the year ended December 31, 2005 compared to 13.2 MBbl/d for the year ended December 31, 2004. The volume increases were primarily attributable to additional well connections partially offset by the natural decline in field production. Condensate production decreased by 0.2 MBbl/d, or 29%, to 0.5 MBbl/d for the year ended December 31, 2005 compared to 0.7 MBbl/d for the year ended December 31, 2004.

Product Purchases. Product purchases for the two months ended December 31, 2005 were $54.9 million which, combined with the $210.8 million recorded for the ten months ended October 31, 2005, increased by $83.1 million, or 46%, to $265.7 million for the year ended December 31, 2005 compared to $182.6 million for the year ended December 31, 2004. Higher commodity prices accounted for $63.6 million of this increase and increased volumes accounted for $19.5 million of this increase.

Operating Expenses. Combined operating expenses of $21.5 million for the year ended December 31, 2005 is an increase of $3.8 million, or 21%, compared to $17.7 million for the year ended December 31, 2004. The combined operating expense consisted of $3.5 million for the two months ended December 31, 2005 and $18.0 million for the ten months ended October 31, 2005. The increase over 2004 was attributable primarily to the impact of processing plant and gathering system expansions.

Depreciation and Amortization. Depreciation and amortization expense for the two months ended December 31, 2005 was $9.2 million which, combined with the $11.3 million recorded for the ten months ended October 31, 2005, totals a combined $20.5 million for the year ended December 31, 2005 compared to $12.2 million for the year ended December 31, 2004, for an increase of $8.3 million, or 68%. The increase is due to the higher carrying value of property, plant and equipment as a result of the DMS Acquisition.

General and Administrative. Combined general and administrative expense of $8.4 million for the year ended December 31, 2005 is an increase of $1.2 million, or 17%, compared to $7.2 million for the year ended December 31, 2004. The allocated combined general and administrative expense consisting of $1.1 million for the two months ended December 31, 2005 and $7.3 million for the ten months ended October 31, 2005 was attributable to higher allocable corporate overhead expenses incurred during 2005 compared to 2004.

Interest Expense. Interest expense for the year ended December 31, 2005 was $11.5 million compared to none for the year ended December 31, 2004. Interest expense in 2005 consists of an allocation of a portion of the interest expense incurred by Targa as a result of borrowing to fund the DMS Acquisition and was recognized in the final two months of 2005. Prior to the DMS Acquisition, there was no allocation of Dynegy indebtedness to the Predecessor Business.

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 "Risk Factors."

Historically, our cash generated from operations has been sufficient to finance our operating expenditures and maintenance and expansion capital expenditures. Prior to our IPO, excess cash was distributed to Dynegy or Targa during their respective periods of ownership. Following our IPO, 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. 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 the closing of our IPO on February 14, 2007, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with the Predecessor Business' parent at the time, either Dynegy or Targa, but were recorded as an adjustment to parent equity on the balance sheet. The primary transactions between the applicable 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. As a result of this accounting treatment, the working capital of the Predecessor Business 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 the applicable parent on behalf of the Predecessor Business.

We had a positive working capital balance of $24.2 million as of June 30, 2007, compared to negative working capital of $294.1 million and $34.4 million as of December 31, 2006 and 2005, respectively. 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 $13.1 million. This increasing working capital trend is attributable to an increase in fair value of the current portion of commodity hedges and decreased accrued liabilities. The decrease in accounts payable was due to lower commodity prices, partially offset by increased volumes, which decreased accounts payable to our producers without an offsetting decrease in receivables due to the accounting treatment discussed above.

Cash Flow. Net cash provided by or used in operating activities, investing activities and financing activities for the six months ended June 30, 2007 and 2006 and the years ended December 31, 2006, 2005 and 2004 were as follows:

	Targa Resource Partners LP	Predecessor Business					
		Targa North Texas LP			Combined	Dynegy	
	Six Months Ended June 30, 2007 (Unaudited)	Six Months Ended June 30, 2006 (Unaudited)	Year Ended December 31, 2006 (Audited)	Two Months Ended December 31, 2005 (Audited)	Year Ended December 31, 2005 (Unaudited)	Ten Months Ended October 31, 2005 (Audited)	Year Ended December 31, 2004 (Audited)
	(In millions of dollars)						
Net cash provided by (used in):							
Operating activities	$ 23.5	$ 3.4	$ 16.2	$ (1.5)	$ 71.2	$ 72.7	$ 58.0
Investing activities	(10.5)	(11.2)	(23.1)	(2.1)	(18.5)	(16.4)	(23.4)
Financing activities	(3.6)	7.8	6.9	3.6	52.7	(56.3)	(34.6)

The discussion of cash flows for the year ended December 31, 2005 is derived from the sum of the cash flows reflected in the Pre-Acquisition Financial Statements and the cash flows reflected in the Post-Acquisition Financial Statements. The combined financial information for the year ended December 31, 2005 is unaudited. Because different bases of accounting were followed in the Pre-Acquisition Financial Statements and the Post-Acquisition Financial Statements, the combined cash flow information for the year ended December 31, 2005 is not prepared on the same basis and, thus, is not in accordance with GAAP. The following discussion based on the combined cash flows is presented for the convenience of investors to facilitate the presentation of a more meaningful discussion of the historical period. The combined cash flows for the Predecessor Business for the year ended December 31, 2005 do not necessarily represent the cash flows that would have occurred during this period had the business been operated by Targa for the entire year.

Cash flow information for the year ended December 31, 2004 is based on Dynegy's results of operations for the Predecessor Business for the year ended December 31, 2004. The results of operations for the year ended December 31, 2004 does not necessarily represent the results that would have been achieved during this period had the business been operated by Targa.

Operating Activities. Net cash provided by operating activities was $23.5 million for the six months ended June 30, 2007 compared to $3.4 million for the six months ended June 30, 2006. The $20.1 million increase was attributable to a lower net loss for the six months ended June 30, 2007, adjusted for non-cash charges and cash settlement of operational transactions, including affiliate transactions, subsequent to our IPO. Prior to the IPO, our operational transactions were settled through an adjustment to partners' capital. Please see the Liquidity and Capital Resources section of this MD&A.

Investing Activities. Net cash used in investing activities was $10.5 million for the six months ended June 30, 2007 compared to $11.2 million for the six months ended June 30, 2006. The $0.7 million, or 6%, decrease was primarily attributable to a $1.0 million decrease in capital spending related to maintenance expenditures. We categorize our capital expenditures as either: (i) maintenance capital expenditures or (ii) expansion capital expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the base levels of production, 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 capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues. The table below outlines our capital expenditures for the six months ended June 30, 2007 and 2006.

	Six Months Ended June 30, 2007	Feb. 14, 2007 to June 30, 2007	Jan. 1, 2007 to Feb. 14, 2007	Six Months Ended June 30, 2006
		(In millions)		
Capital expenditures:				
Expansion	$ 5.2	$ 3.5	$ 1.7	$ 4.9
Maintenance	5.3	3.8	1.5	6.3
	$ 10.5	$ 7.3	$ 3.2	$ 11.2

Our capital expenditures for 2006 were $11.7 million for maintenance capital expenditures and $11.3 million for expansion capital expenditures.

Over the three years ended December 31, 2006, our expansion capital expenditures have averaged $10.2 million and ranged from a high of $13.5 million to a low of $5.7 million. We estimate that our expansion capital expenditures will be approximately $10.1 million in 2007. 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.

Net cash used in investing activities was $23.1 million for the year ended December 31, 2006 compared to $18.6 million for the year ended December 31, 2005. The $4.5 million, or 24% increase was attributable to capital spending related to the refurbishment of an additional cryogenic train at our Chico plant, the purchase of an additional gathering system and other expansion expenditures.

Net cash used in investing activities was $18.6 million for the year ended December 31, 2005 compared to $23.4 million for the year ended December 31, 2004. The $4.8 million, or 21%, decrease is primarily due to the completion of a major Barnett Shale gathering system expansion project offset by an increase in major maintenance expenditures of $1.2 million due to the increased size of our gathering systems and the effect of higher utilization of our field compression facilities.

Financing Activities. Net cash provided by financing activities for the six months ended June 30, 2007 primarily reflects the proceeds from our IPO, borrowings under our credit facility, and deemed parent contributions prior to the IPO, offset by payments of debt, and the payment of offering costs and debt issuance costs on our credit facility. Net cash provided by financing activities for the six months ended June 30, 2006 represents the contribution to us by Targa of the net cash required for principal and interest on allocated parent debt.

Net cash used in financing activities prior to our IPO represents the pass through of our net cash flow to Dynegy prior to the October 31, 2005 DMS Acquisition, and net cash provided by financing activities represents the contribution to us by Targa of the net cash required for principal and interest on allocated parent debt following the DMS Acquisition.

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 make significant expenditures during the next year for the construction of additional natural gas gathering and processing infrastructure.

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

Description of Credit Agreement. On February 14, 2007, we entered into a credit agreement which provides for a five-year $500 million revolving credit facility. 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. We borrowed $342.5 million under our credit facility and concurrently repaid $48.0 million under our credit facility with 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 in our IPO. The net proceeds of $294.5 million from this borrowing, together with approximately $371.2 million of net proceeds from the IPO (after payment of offering costs, debt issuance costs and necessary operating cash reserve balances), were used to repay approximately $665.7 million of affiliate indebtedness. There have been no additional borrowings as of June 30, 2007 under our revolving credit facility.

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 5.75 to 1.00, as of June 30, 2007, subject to certain adjustments. We are also required to maintain a leverage ratio of no more than 5.00 to 1.00 on the last day of any fiscal quarter ending on or after September 30, 2007. In certain circumstances following an acquisition, the Partnership may elect to increase the maximum permitted leverage ratio by 0.50x for a period of up to one year. 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.

Any subsequent replacement of our credit agreement or any new indebtedness could have similar or greater restrictions. As of June 30, 2007, we had approximately $205.5 million available under the credit agreement, after giving effect to our outstanding borrowings.

Concurrent with this offering, the amount we may borrow under our credit agreement will be increased by $250 million to $750 million. This increase, combined with existing availability, will be used to fund a portion of the purchase price for the Acquired Businesses and for the issuance of letters of credit. Concurrently with the closing of this offering and the acquisition of the Acquired Businesses, we expect to have approximately $673.4 million of debt outstanding under our amended credit facility at variable interest rates and approximately $40 million of letters of credit issued to trade counterparties. To the extent the underwriter's exercise their option to purchase additional common units in this offering, we will use the net proceeds to reduce borrowings under our amended credit facility.

Contractual Obligations.

A summary of our existing contractual cash obligations over the next several fiscal years, as of December 31, 2006:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	4-5 Years	More Than 5 Years
	(In millions of dollars)				
Debt obligations(1)(2)	$ 864.0	$ 281.1	$ 9.8	$ 9.8	$ 563.3
Interest on debt obligations(3)	284.2	63.0	89.8	87.8	43.6
Operating leases	0.3	0.1	0.2	—	—
Capacity payments(4)	8.3	2.6	4.9	0.8	—
Asset retirement obligations	1.7	—	—	—	1.7
	$ 1,158.5	$ 346.8	$ 104.7	$ 98.4	$ 608.6

(1) Represents required future principal repayments of debt obligations allocated from Targa.

(2) The allocated debt from Targa of $864.0 million at December 31, 2006 was partially repaid and the remainder of the allocated debt was treated as contributed capital on February 14, 2007 in conjunction with our IPO. The following table shows the extinguishment of the allocated debt from Targa:

	(In millions)
Allocated debt from Targa Resources at December 31, 2006(a)	$ 864.0
Net proceeds from IPO	(371.2)
Net proceeds from new credit facility	(294.5)
Contributed capital from Targa	(198.3)
	$ —

(a) Allocated debt presented above represents indebtedness incurred by Targa in connection with the DMS Acquisition that has been allocated to the North Texas System. 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, the guarantee was terminated, the collateral interest was released and the allocated indebtedness was retired.

(3) Represents interest expense on allocated debt, based on interest rates as of December 31, 2006. We used an average rate of 7% to estimate our interest on variable rate debt obligations.

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

Our contractual obligations changed due to the repayment of affiliated debt and borrowings under our credit facility. A summary of our remaining contractual obligations as it relates to our debt as of June 30, 2007 is presented in the table below:

	Payments Due by Period				
Contractual Obligations	Total	Remaining Six Months of 2007	2008-2009	2010-2011	2012
	(In millions)				
Debt obligations	$ 294.5	$ —	$ —	$ —	$294.5
Interest on debt obligations(1)	95.3	10.3	41.2	41.2	2.6
	$ 389.8	$ 10.3	$ 41.2	$ 41.2	$297.1

(1) Represents interest expense on the Partnership's revolving credit facility using an average interest rate of 7%.

Recent Accounting Pronouncements

The accounting standard setting bodies have recently issued the following accounting guidance that will or may affect our future financial statements:

Statement of Financial Accounting Standards ("SFAS") 157 "*Fair Value Measurements*," and

SFAS 159, "*Fair Value Option for Financial Assets and Financial Liabilities — Including an amendment of FASB Statement No. 115*."

For additional information regarding these recent accounting developments and others that may affect our future financial statements, please read Note 2 to the Consolidated Financial Statements of Targa Resources Partners LP.

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. Substantially all of our revenues are derived from percent-of-proceeds contracts under which 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. 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 inherent in our contract mix 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 June 30, 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 2007 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. 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 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 the commodity price exposure associated with additional expected equity commodity volumes without creating volumetric risk. We intend to continue to manage our exposure to commodity prices in the future for the North Texas System, as well as those associated with the LOU System and the SAOU System, 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.

Summary of Our Hedges

At December 31, 2005, we had no open commodity derivative positions. During 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). For the year ended December 31, 2006, our operating revenue was increased by net hedge settlements of $4.6 million. For the six months ended June 30, 2007, net hedging activities increased our operating revenues by $5.0 million. We had no hedge settlements during the first six months of 2006. At June 30, 2007, we had the following open commodity derivative positions designated as cash flow hedges:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu/d 2007	2008	2009	2010	2011	2012	Fair Value (In thousands)
Swap	IF-NGPL MC	$ 8.56	8,152	—	—	—	—	—	$ 2,975
Swap	IF-NGPL MC	8.43	—	6,964	—	—	—	—	2,644
Swap	IF-NGPL MC	8.02	—	—	6,256	—	—	—	340
Swap	IF-NGPL MC	7.43	—	—	—	5,685	—	—	(713)
Swap	IF-NGPL MC	7.34	—	—	—	—	2,750	—	(181)
Swap	IF-NGPL MC	7.18	—	—	—	—	—	2,750	(90)
			8,152	6,964	6,256	5,685	2,750	2,750	$ 4,975
Swap	IF-Waha	8.73	5,460	—	—	—	—	—	1,836
Swap	IF-Waha	8.53	—	4,657	—	—	—	—	1,102
Swap	IF-Waha	7.96	—	—	4,196	—	—	—	(177)
Swap	IF-Waha	7.38	—	—	—	3,809	—	—	(659)
Swap	IF-Waha	7.36	—	—	—	—	2,250	—	(200)
Swap	IF-Waha	7.18	—	—	—	—	—	2,250	(136)
			5,460	4,657	4,196	3,809	2,250	2,250	1,766
Total Swaps			13,612	11,621	10,452	9,494	5,000	5,000	6,741
Floor	IF-NGPL MC	6.45	520	—	—	—	—	—	56
Floor	IF-NGPL MC	6.55	—	1,000	—	—	—	—	259
Floor	IF-NGPL MC	6.55	—	—	850	—	—	—	186
			520	1,000	850	—	—	—	501
Floor	IF-Waha	6.70	350	—	—	—	—	—	37
Floor	IF-Waha	6.85	—	670	—	—	—	—	168
Floor	IF-Waha	6.55	—	—	565	—	—	—	113
			350	670	565	—	—	—	318
Total Floors			870	1,670	1,415	—	—	—	819
									$ 7,560

NGLs

Instrument Type	Index	Avg. Price $/gal.	Barrels/d 2007	2008	2009	2010	2011	2012	Fair Value (In thousands)
Swap	OPIS-MB	$ 0.96	3,416	—	—	—	—	—	$ (3,375)
Swap	OPIS-MB	0.93	—	2,910	—	—	—	—	(5,136)
Swap	OPIS-MB	0.89	—	—	2,548	—	—	—	(2,863)
Swap	OPIS-MB	0.87	—	—	—	2,159	—	—	(1,718)
Swap	OPIS-MB	0.90	—	—	—	—	1,250	—	(262)
Swap	OPIS-MB	0.90	—	—	—	—	—	750	69
			3,416	2,910	2,548	2,159	1,250	750	$ (13,285)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels/d 2007	2008	2009	2010	2011	2012	Fair Value (In thousands)
Swap	NY-WTI	$72.82	439	—	—	—	—	—	$ 126
Swap	NY-WTI	70.68	—	384	—	—	—	—	(223)
Swap	NY-WTI	69.00	—	—	322	—	—	—	(356)
Swap	NY-WTI	68.10	—	—	—	301	—	—	(274)
Total Swaps			439	384	322	301	—	—	(727)
Floor	NY-WTI	$58.60	25	—	—	—	—	—	$ 2
Floor	NY-WTI	60.50	—	55	—	—	—	—	48
Floor	NY-WTI	60.00	—	—	50	—	—	—	56
Total Floor			25	55	50	—	—	—	106
			464	439	372	301	—	—	$ (621)

Note: The 2007 volume information represents the volume hedged for the last six months of 2007.

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.

Consistent with our strategy to mitigate commodity price exposure through prudent hedging arrangements, certain commodity price hedging instruments will be transferred to us in connection with our acquisition of the Acquired Businesses. The commodity risk exposure of the Acquired Businesses has been managed similarly to the North Texas System and we expect that the combined businesses will be managed to hedge the commodity price exposure associated with a significant portion of expected equity volumes of natural gas and NGLs in the near to mid-term. For more information regarding the derivative instruments associated with the hedging program for the Acquired Businesses, please read Notes 7 and 9 to the unaudited combined financial statements for the SAOU and LOU Systems and Notes 8 and 11 to the audited combined financial statements for the SAOU and LOU Systems.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of our variable rate debt under our amended credit facility. To the extent that interest rates increase, our interest expense for our revolving debt will also increase. On February 14, 2007, we entered into a $500 million revolving credit agreement. As of June 30, 2007, there were borrowings of approximately $294.5 million outstanding under this credit facility. Upon completion of this offering, we expect to have approximately $673.4 million of debt outstanding under our amended credit facility at variable interest rates. An increase of 1 percentage point in the interest rates will result in an increase in annual interest expense of $6.7 million.

We may enter into hedges for a portion of our floating interest rate exposure under our amended credit facility.

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 by Targa under the agreements it has with us could materially and adversely impact our ability to operate and make distributions to our unitholders.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates. The policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements, because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain.

Revenue Recognition.

Our primary types of sales and service activities reported as operating revenue include:

- sales of natural gas, NGLs and condensate; and
- natural gas processing, from which we generate revenue through the compression, gathering, treating and processing of natural gas.

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

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

We generally report revenues gross in the combined statements of operations, in accordance with Emerging Issues Task Force ("EITF") Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent." Except for fee-based contracts, we act as the principal in these transactions where we receive natural gas or NGLs, take title to the commodities, and incur the risks and rewards of ownership.

Use of Estimates. The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect our reported financial positions and results of operations. We review significant estimates and judgments affecting our consolidated financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. 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 our assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from our estimates.

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

Asset Group	Service Life (Years)
Natural gas gathering systems and processing facilities	15 to 25
Office and miscellaneous equipment	3 to 7

Expenditures for maintenance and repairs are generally expensed as incurred. However, expenditures to refurbish (i.e., certain repair and maintenance expenses) assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset.

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

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

In accordance with SFAS No. 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 Operation.

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

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

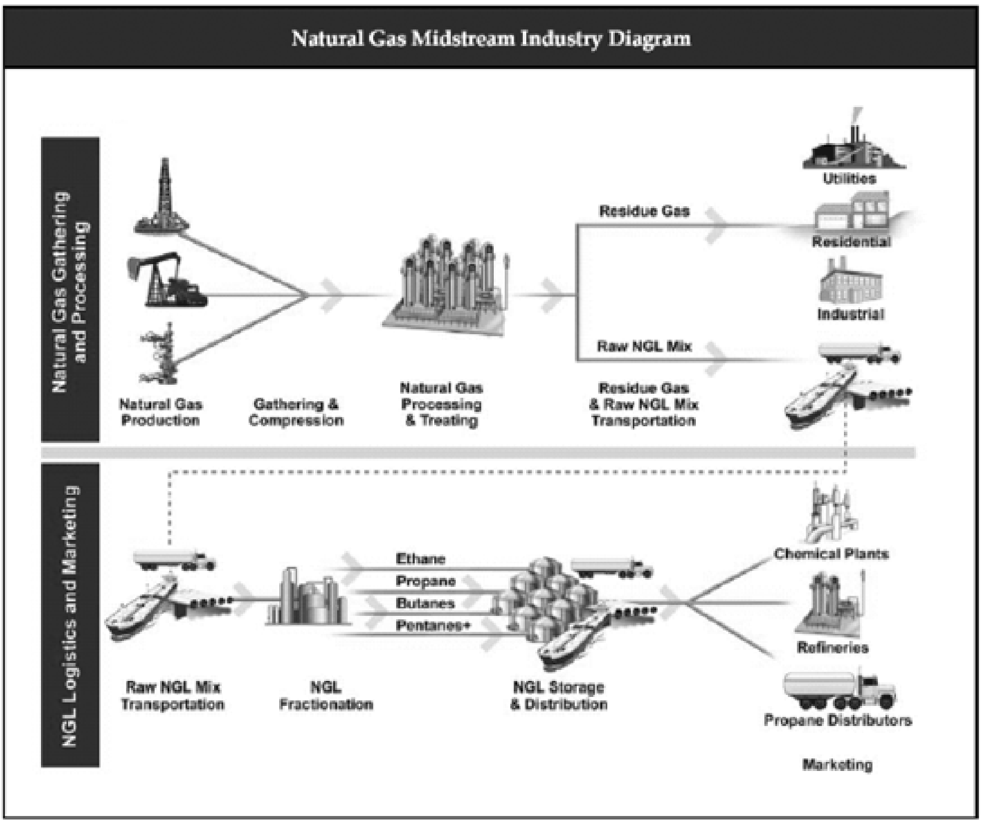
Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being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

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

Natural Gas Imbalance Accounting. Quantities of natural gas 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, gas imbalances over-delivered are valued at the lower of cost or market; gas imbalances under-delivered are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas. Under the contracts, imbalance cash-outs are recorded as a sale or purchase of natural gas, as appropriate.

OUR INDUSTRY

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 NGLs such as ethane, propane, normal butane, isobutane and natural gasoline. Most natural gas produced at the wellhead contains NGLs. Natural gas produced in association with crude oil typically contains higher concentrations of NGLs 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 NGLs, leaving residual dry gas that meets interstate transmission pipeline and commercial quality specifications. Furthermore, they produce marketable NGLs, 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, then 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, that 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 NGLs, 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 NGLs 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 NGLs 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 NGLs 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 NGLs is known as the “frac spread.” Because NGLs 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 our 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 NGLs.
- ***Keep-Whole.*** A keep-whole arrangement allows the processor to keep 100% of the NGLs 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 NGLs. As a result, a

processor with these types of contracts benefits when the value of the NGLs 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 NGLs.

- ***Fee-Based.*** Under a fee-based contract, the processor receives a fee per gallon of NGLs produced or per Mcf of natural gas processed. Under this arrangement, a processor would have no commodity price risk exposure.

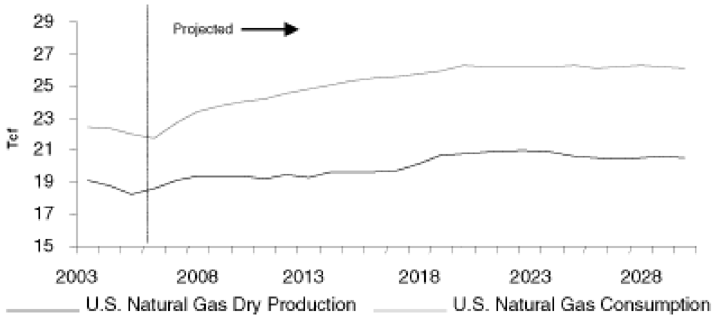
Fractionation. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate 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. 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 content 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.

A typical barrel of NGLs consists of ethane, propane, normal butane, isobutane and natural gasoline.

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 NGLs 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.

Natural Gas Demand and Production. Natural gas is a critical component of energy consumption in the United States. According to the Energy Information Administration, or the EIA, total annual domestic consumption of natural gas is expected to increase from approximately 21.7 trillion cubic feet, or Tcf, in 2006 to approximately 26.1 Tcf in 2030. The industrial and electricity generation sectors are the largest users of natural gas in the United States. During the last three years, these sectors accounted for approximately 62% of the total natural gas consumed in the United States. In 2006, the end-user commercial and residential sectors accounted for approximately 34% of the total natural gas consumed in the United States. During the last three years, the United States has on average consumed approximately 22.0 Tcf per year, with average annual domestic production of approximately 18.5 Tcf during the same period. Driven by growth in natural gas demand and high natural gas prices, domestic natural gas production is projected to increase from 18.6 Tcf per year to 21.0 Tcf per year between 2006 and 2022. The graph below represents projected U.S. natural gas production versus U.S. natural gas consumption (in Tcf) through the year 2030.



Source: Energy Information Association

BUSINESS

Our Partnership

We are a growth-oriented Delaware limited partnership formed by 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 in north Texas, which is one of the most active natural gas basins in the U.S. as measured by drilling activity. 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. Consistent with this strategy, we will acquire certain natural gas gathering and processing operations located in the Permian Basin of west Texas and southwest Louisiana from Targa for aggregate consideration of $705 million, subject to certain adjustments, concurrently with the closing of this offering. We believe this acquisition will increase our scale of operations, provide geographic diversity and position us to pursue future growth opportunities. At June 30, 2007, Targa had total assets of $3.4 billion (including the assets of the Partnership, which represent $1.1 billion of this amount). The Acquired Businesses to be purchased by us concurrently with the closing of this offering represent $297 million of this amount. Over time, Targa intends, but is not obligated, to offer us the opportunity to purchase substantially all of its remaining businesses.

Our operations currently consist of an extensive network of approximately 4,000 miles of integrated gathering pipelines that gather and compress natural gas received from approximately 2,650 receipt points in the Fort Worth Basin, two natural gas processing plants that compress, treat and process the natural gas and a fractionator that fractionates a portion of our raw NGLs produced in our processing operations into NGL products. The North Texas System serves a fourteen-county natural gas producing region in the Fort Worth Basin that includes production from the Barnett Shale formation and other shallower formations, which are subsurface rock formations containing hydrocarbons, including the Bend Conglomerate, Caddo, Atoka, Marble Falls, and other Pennsylvanian and upper Mississippian formations. The North Texas System includes the following:

- the Chico system, located in the northeast part of the Fort Worth Basin, which consists of:
  - — approximately 1,900 miles of natural gas gathering pipelines with approximately 1,850 active connections to producing wells and central delivery points;
  - — a cryogenic natural gas processing plant with throughput capacity of approximately 265 MMcf/d (for the year ended December 31, 2006 and the six months ended June 30, 2007, the average daily plant inlet volume was approximately 151 MMcf/d and 149 MMcf/d, respectively); and
  - — an 11,500 Bbls/d fractionator located at the processing plant that enables us, based on market conditions, to either fractionate a portion of our raw NGL mix into separate NGL products for sale into local and other markets or deliver raw NGL mix to Mont Belvieu for fractionation primarily through Chevron's West Texas LPG Pipeline, L.P ("WTLPG");
- the Shackelford system, located on the western side of the Fort Worth Basin, which consists of:
  - — approximately 2,100 miles of natural gas gathering pipelines with approximately 800 active connections to producing wells and central delivery points; and
  - — a cryogenic natural gas processing plant with throughput capacity of approximately 13 MMcf/d (for the year ended December 31, 2006 and the six months ended June 30, 2007, the average daily plant inlet volume was approximately 11 MMcf/d and 11 MMcf/d, respectively); and
  - — a 32-mile, 10-inch diameter natural gas pipeline connecting the Shackelford and Chico systems, which we refer to as the "Interconnect Pipeline," that is used primarily to send natural gas gathered in excess of the Shackelford system's processing capacity to the Chico plant.

The Acquired Businesses

We will acquire from Targa all direct and indirect equity interests in Targa Texas Field Services LP, a Delaware limited partnership ("Targa Texas"), and Targa Louisiana Field Services LLC, a Delaware limited liability company ("Targa Louisiana"), concurrently with the closing of this offering. Targa Texas owns the SAOU System and Targa Louisiana owns the LOU System.

The SAOU System includes the following:

- approximately 1,350 miles of gathering pipelines covering approximately 4,000 square miles in portions of ten counties near San Angelo, Texas, including:
  - — approximately 850 miles of low-pressure gathering systems, which allow wells that produce at progressively lower field pressures as they age to remain connected to the gathering system and to continue to produce for longer periods than otherwise possible; and
  - — approximately 500 miles of high pressure gathering pipelines that deliver the natural gas to its processing plants currently operating in the region. The gathering system has 27 compressor stations at several central delivery points to inject low pressure gas into these high pressure pipelines;
- approximately 3,000 active connections to producing wells and/or central delivery points;
- the Mertzon and Sterling processing plants, which are refrigerated cryogenic plants and have aggregate processing capacity of approximately 110 MMcf/d; and
- the Conger cryogenic processing plant with capacity of approximately 25 MMcf/d that is not currently operating, but can be reactivated on short notice to meet additional needs for processing capacity.

The Mertzon processing plant currently delivers residue gas to the Rancho Pipeline owned by Kinder Morgan, and NGLs produced by the plant are delivered to a pipeline owned by DCP Midstream, LLC ("DCP") that delivers such NGLs to Targa-owned fractionators and the Mont Belvieu hub. The Sterling processing plant has residue gas connections to pipelines owned by affiliates of Atmos Energy Corporation, or Atmos, El Paso Natural Gas Company, or El Paso, ONEOK and Enterprise Products/ET Fuel, and NGLs are delivered to the West Texas NGL pipeline, owned by Chevron, which also accesses the Mont Belvieu hub.

The LOU System includes the following:

- approximately 700 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, which are refrigerated cryogenic plants that have aggregate processing capacity of approximately 260 MMcf/d;
- an integrated fractionation facility at the Gillis plant with processing capacity of approximately 13 MBbls/d; and
- an approximately 60-mile intrastate pipeline system.

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. As a result of the location and flexibility of its intrastate pipeline assets and the reliability of its natural gas supplies in the area, the LOU System has a leading market share in the Lake Charles area. It also has access to both interstate natural gas supplies and markets as well as access to the liquid NGL markets of the Louisiana and Texas gulf coast. For example, 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 industrial customers that burn the Gillis plant residue gas readily burn richer (higher Btu) gas which provides the LOU 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.

Strategies

Our primary business objective is to increase our cash distribution per unit over time. We intend to accomplish this objective by executing the following strategies:

- ***Increasing the profitability of our existing assets.*** With our extensive network of gathering systems and two natural gas processing facilities, we are well positioned to capitalize on the active development and growing production from the Barnett Shale and the other Fort Worth Basin formations. The SAOU System will provide us access to the Permian Basin, which is characterized by long-lived, multi-horizon oil and gas reserves that have low natural production declines. In addition, the LOU System will provide us access to onshore basins in south Louisiana. Our existing assets and the Acquired Businesses provide 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 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 appropriately managed, our current contract mix allows us to optimize the profitability of our assets 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 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, NGL and condensate equity volumes for the years 2007 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 for the North Texas System, as well as for the LOU System and the SAOU System, 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 leverage our existing market position and leverage our core competitiveness in the midstream energy industry.

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

  — regions where treating and/or processing is required to access end-markets;

— regions where permitting, drilling and workover activity is high;

— regions with the potential for long-term acreage dedications;

— regions with a strong base of current production and the potential for significant future development; and

— regions 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 and the potential for higher capacity utilization and expansion of those assets, as well as acquisitions in other related lines of our midstream business and new geographic areas of operation. Certain 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.

- ***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 the strategies. In addition, we intend to pursue acquisition opportunities as well as organic growth opportunities with Targa and with Targa's assistance. Consistent with our acquisition of the Acquired Businesses, we may also acquire assets or businesses directly from Targa, which will provide us access to a broader array of growth opportunities than those 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. After this offering, Targa will continue to be 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. We will acquire assets from Targa in the Permian Basin of west Texas and the Louisiana Gulf Coast concurrently with the completion of this offering. These operations are integrated with Targa's NGL logistics and marketing business that extends services to customers across the southern, southeastern and western United States. Targa has an experienced and knowledgeable executive management team and an 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, consistent with our acquisition of the Acquired Businesses, 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, which is one of the most active natural gas basins in the U.S. as measured by drilling activity. 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. Because natural gas produced in the Permian Basin typically has higher NGL content, processing is required before natural gas can be transported via interstate pipelines and the resulting NGL recovery from processing this natural gas is high, resulting in profitable processing margins under percent-of-proceeds contracts. 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 south 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. As a result of the location and flexibility of its intrastate pipeline assets and the reliability of its natural gas supplies in the area, the LOU System has a leading market share in the Lake Charles area. It also has access to both interstate natural gas supplies and markets as well as access to the liquid 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 applications 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. The Acquired Businesses have been managed with similar systems, practices and personnel.

- ***Low maintenance capital expenditures.*** Our maintenance capital expenditures have averaged approximately $11.6 million over the three years ended December 31, 2006. The combined maintenance capital expenditures of the SAOU System and the LOU System have averaged approximately $3.8 million over the three years ended December 31, 2006. 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. Consistent with our strategy to mitigate commodity price exposure through prudent hedging arrangements, certain commodity price hedging instruments will be transferred to us in connection with our acquisition of the Acquired Businesses. The commodity risk exposure of the Acquired Businesses has been managed similarly to the North Texas System and we expect that the combined businesses will be managed to hedge the commodity price exposure associated with a significant portion of expected equity volumes of natural gas and NGLs in the near to mid-term.

  For additional information regarding our hedging activities, please see "Management's Discussion and Analysis of Financial Condition and Results of Operation — Quantitative and Qualitative Disclosures about Market 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 for existing and expected equity production as market conditions permit.

- ***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 a reputation as a reliable operator by providing high quality services and focusing on the needs of our customers. The Acquired Businesses maintain a similar reputation and customer base. 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. These services are essential to gather, process and treat wellhead gas to meet pipeline standards and to extract natural gas liquids for sale into industrial and commercial markets. 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. The Acquired Businesses provide a similar package of midstream services.
- ***Experienced management team.*** Targa has an experienced and knowledgeable executive management team that will own an approximately 5.5% direct and indirect ownership interest in us following this offering. Targa's executive management team is committed to executing our business strategy and 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 extensive 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 "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, or Warburg Pincus, a private equity firm. In April 2004, Targa purchased the Acquired Businesses from ConocoPhillips Company, or ConocoPhillips, for $247 million and, in October 2005, Targa purchased substantially all of the midstream assets of Dynegy, Inc. and its affiliates, or 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 June 30, 2007, Targa had total assets of $3.4 billion (including the assets of the Partnership, which represent $1.1 billion of this amount), with the Acquired Businesses to be purchased by us concurrently with the closing of this offering representing $297 million of this amount.

Following our acquisition of the Acquired Businesses from Targa, Targa's businesses will include:

- ***Natural Gas Gathering and Processing Division*** — Targa will continue to gather and process natural gas from the Permian Basin in west Texas and southeast New Mexico and the offshore regions of the Texas and Louisiana Gulf Coast. Targa will own approximately 4,000 miles of natural gas pipelines with approximately 4,000 active connections to producing wells and central delivery points, operate 9 processing plants (some of which are jointly owned) and will have a partial interest in six additional processing plants that are operated by others. For the six months ended June 30, 2007, these assets processed an average inlet plant volume of approximately 1,500 MMcf/d of natural gas and produced an average of approximately 60 MBbls/d of NGLs, in each case, net to its 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 65 MMBbls. 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 will continue to own, operate or lease 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 will also continue to own 21 pressurized NGL barges, 81 transport tractors and 95 tank trailers and lease 897 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. Consistent with our acquisition of the Acquired Businesses, we expect to have the opportunity to make acquisitions directly from Targa in the future. 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. Targa has retained such flexibility because it believes it is in the best interests of its shareholders to do so. 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 will 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.

Upon completion of this offering, Targa will retain a significant indirect interest in our partnership through its ownership of a 25.5% limited partner interest and a 2% general partner interest in us. We are party to an omnibus agreement with Targa that governs our relationship with them regarding certain reimbursement and indemnification matters. Please see "Certain Relationships and Related Transactions — Omnibus Agreement." In addition, to carry out operations, our general partner and its affiliates, which are indirectly owned by Targa, employ approximately 880 people, some of whom provide direct support to our operations. We do not have any employees. Please see "— Employees."

While our relationship with Targa is a significant advantage, it is also a source of potential conflicts. For example, Targa is not restricted from competing with us. Targa will retain 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 "Conflicts of Interest and Fiduciary Duties."

Our Systems

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

Natural Gas Gathering and Processing Systems

Facility	County/Approximate Square Miles	Approximate Gross Processing Capacity (MMcf/d)	2006 Approximate Inlet Throughput Volume (MMcf/d)	2006 Approximate NGL Production (MBbl/d)	Process Type	Approximate Fractionation Capacity (MBbl/d)
Permian Basin						
Mertzon	Irion, TX	48	30.3	5.5	RC(2)	N/A
Sterling	Sterling, TX	62	52.4	8.5	RC	N/A
Conger(1)	Sterling, TX	25	N/A	N/A	RC	N/A
		135	82.7	14.0		
Gathering Area	10 counties/4,000 square miles					
Louisiana Gulf Coast						
Gillis	Calcasieu, LA	180	129.2	7.9	RC	13.0
Acadia	Acadia, LA	80	39.8	1.8	RC	N/A
		260	169.0	9.7		13.0
Gathering Area	12 parishes/3,800 square miles					
North Texas						
Chico	Wise, TX	265	150.5	17.6	Cryo(3)	11.5
Shackelford	Shackelford, TX	13	11.3	1.3	Cryo(4)	N/A
		278	161.8	18.9		11.5
Gathering Area	14 counties/2,500 square miles					

(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) RC — Refrigerated Cryogenic Expander.

(3) Cryo — Cryogenic Expander.

(4) Cryo — Cryogenic Expander.

The North Texas System

Gathering Systems

The North Texas System consists of approximately 4,000 miles of pipelines that, in aggregate, gather wellhead natural gas from approximately 2,650 meters for transport to the Chico and Shackelford natural gas processing facilities. This system consists of two distinct systems: the Chico Gathering System which gathers natural gas from Denton, Montague, Wise, Clay, Jack, Palo Pinto and Parker counties on the eastern part of the North Texas System; and the Shackelford Gathering System, 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 two gathering systems are connected via a high-pressure 32-mile, 10-inch diameter pipeline, or the Interconnect Pipeline. This interconnection between the gathering systems allows us to send natural gas in excess of the Shackelford system's processing capacity to the Chico plant.

Chico Gathering System. The Chico Gathering System consists of approximately 1,900 miles of primarily low pressure gathering pipelines. 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 26 compressor stations and then transported via one of several high-pressure pipelines to the Chico plant. For the year ended December 31, 2006 and the six months ended June 30, 2007, this system gathered approximately 157 MMcf/d and 155 MMcf/d of natural gas, respectively. As of June 30, 2007, there were approximately 1,850 active meters, both wellhead and central delivery points, connected to the Chico Gathering System.

Shackelford Gathering System. The Shackelford Gathering System consists of approximately 2,100 miles of natural gas gathering pipelines. The western and southern portions of the Shackelford Gathering System gather natural gas that is transported on intermediate-pressure pipelines to the Shackelford plant. The approximately 18 MMcf/d of natural gas gathered from the northern and eastern portions of the Shackelford Gathering System is typically transported on the Interconnect Pipeline to the Chico plant for processing. This natural gas is compressed at 11 compressor stations to achieve sufficient pressure to enter the high pressure Interconnect Pipeline. For the year ended December 31, 2006, and the six months ended June 30, 2007, this system gathered approximately 12 MMcf/d and 12 MMcf/d of natural gas, respectively. As of August 2007, there were approximately 800 active meters, including both wellhead and central delivery points, connected to the Shackelford Gathering System.

Processing Plants

Chico Processing Plant. 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. Plant inlet volumes consist of separate high-pressure (830 psig), intermediate-pressure (400 psig) and low-pressure (5 psig) natural gas streams. The intermediate-pressure stream and low pressure stream are compressed to a plant pressure of 830 psig. The three inlet streams are then commingled for processing. The commingled stream is treated, dehydrated and then processed. 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.

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 early results of drilling in some areas such as Montague County indicate an increase in the CO_2 content of the gas. In anticipation of a continuing increase in CO_2, we are developing engineering cost estimates to install new or refurbished existing CO_2 treating capacity at either the Chico plant or at the East Chico compressor station. We believe that existing and future CO_2 treating charges will substantially cover these expenditures and associated operating costs.

Shackelford Processing Plant. 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. Plant inlet volumes are compressed to approximately 720 psig by three inlet compressors before being dehydrated and processed. The Shackelford facility also includes two 40,000 and two 12,600 gallon NGL storage tanks, an iron sponge for hydrogen sulfide removal and inlet scrubbers.

Market Access

Chico System 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. Currently, approximately 602,300 gallons per day of NGLs are delivered from the Chico processing facility by pipeline and approximately 118,800 gallons per day of NGL products are 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 trucks 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 sold as NGLs via high pressure trucks which move the product to an injection point on the WTLPG Pipeline at Bridgeport to be shipped to Mont Belvieu. Occasionally, this high pressure condensate product is shipped via truck directly to Mont Belvieu.

Our connections to multiple inter-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.

Shackelford System Market Access. 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, or 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.

Overview of Fort Worth Basin/Bend Arch

Unless indicated otherwise, the information presented below is based on information developed by us, either through general research or our executive management team's experience in the energy industry.

History. The Fort Worth Basin/Bend Arch is a mature crude oil and natural gas producing basin located in north Texas, which is one of the most active natural gas basins in the U.S. as measured by drilling activity. Drilling in the Fort Worth Basin/Bend Arch first began in 1923 with the discovery of crude oil. The Fort Worth Basin/Bend Arch has recently experienced a significant increase in drilling activity and is exhibiting year-over-year production growth. Information contained in reports we obtained from W.D. Von Gonten & Company ("Von Gonten") indicates that over its history the basin has produced in aggregate approximately 810 MMBbls of oil and approximately 11 Tcf of natural gas, with natural gas production increasing over time. These reports also indicate that (i) currently, natural gas production averages approximately 4.0 Bcf/d in the basin and (ii) due to the Fort Worth Basin/Bend Arch's maturity and its geologic character, existing natural gas production, without the benefit of additional drilling in the basin, is declining at approximately 5% to 10% per year, making the basin a relatively stable, long-lived source of production volume. This base decline is more than offset by some of the most active drilling in North America, both in the Barnett Shale and other Fort Worth Basin formations.

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, Enbridge, J-W Operating, Davis Gas Processing, Hanlon Gas Processing, and Upham Oil and Gas. 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.

The SAOU System

The SAOU System consists of an approximately 1,350 mile gathering system 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 provide it with a competitive advantage to connect new wells and to process additional natural gas in its existing processing plants.

Gathering System

The SAOU System consists of approximately 1,350 miles of gathering pipelines covering approximately 4,000 square miles in portions of 10 counties near San Angelo, Texas. The system is connected to approximately 3,000 producing wells and/or central delivery points. In the six months ended June 30, 2007, the system gathered approximately 90 MMcf/d of natural gas. The system has approximately 850 miles of low-pressure gathering systems, allowing wells producing at progressively lower field pressures as they age to remain connected to the gathering system and to continue to produce for longer periods than otherwise possible. The system also contains approximately 500 miles of high pressure gathering pipelines to deliver the natural gas to its processing plants in the Permian Basin. The gathering system has 27 compressor stations at several central delivery points to inject low pressure gas into these high pressure pipelines.

Processing Plants

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. Additionally, 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

Market Access

The Mertzon processing plant currently delivers residue gas to the Rancho Pipeline owned by Kinder Morgan, and NGLs produced by the plant are delivered to a pipeline owned by DCP that delivers such NGLs to the Gulf Coast Fractionators (in which Targa owns an interest) and the Mont Belvieu hub. The Sterling processing plant has residue gas connections to pipelines owned by affiliates of Atmos, El Paso, ONEOK and Enterprise Products/ET Fuel, and NGLs are delivered to the West Texas NGL pipeline, owned by Chevron, which also accesses the Mont Belvieu hub.

Overview of the Permian Basin

The Permian Basin is characterized by long-lived, multi-horizon oil and gas reserves that have low natural production declines. The first commercial well in the Permian Basin was completed in 1921 and aggregate production from the basin since that time has been approximately 33,000 MMBbls of oil and approximately 106,000 Bcf of natural gas. Currently, approximately 831 MBbls/d of oil and approximately 4.7 Bcf/d of natural gas are being produced out of the Permian Basin, comprising approximately 17% of total U.S. oil production and approximately 7% of total U.S. natural gas production. Natural gas produced in the Permian Basin typically has high amounts of imbedded NGLs, which is commonly referred to in the industry as rich gas. Rich gas makes processing a necessity before natural gas can be transported via interstate pipeline and provides for high NGL recovery. These characteristics provide for an attractive natural gas gathering and processing environment, as supplies are relatively stable and processing economics are generally favorable.

Drilling and workover activity to increase oil and natural gas production in the Permian Basin has increased over the last several years, driven primarily by higher oil and natural gas prices. Workover activity is designed to allow existing wells to produce more oil and natural gas through recompletions, enhanced artificial lift, formation stimulation, enhanced oil recovery and other techniques. As a result of this activity, natural gas producing wells in the Permian Basin have increased from approximately 100,000 producing wells in 2000 to approximately 115,000 producing wells in 2006.

Competition

The SAOU System competes primarily with Davis Gas Processing to the south and southwest, DCP 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, remains in a strong competitive position 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.

The LOU System

The LOU System consists of approximately 700 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 System

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 at Acadia or Gillis via three main trunk lines. For the six months ended June 30, 2007, the gathering system gathered approximately 178 MMcf/d of natural gas.

Processing Plants

The processing plants are the Gillis and Acadia processing plants. Both of these processing plants are refrigerated cryogenic plants that have aggregate processing capacity of approximately 260 MMcf/d. Natural gas and raw NGL mix 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.

Fractionation Facility

The Gillis fractionation facility is integrated with the Gillis processing plant and receives raw NGL mix from natural gas processed onsite at the Gillis plant as well as from the system's Acadia plant. 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 or truck.

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 MMBtu/d of natural gas, through both medium-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 the gathering system to interconnect with other interstate and intrastate pipelines carrying processable gas positions the 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 FERC or Coast Guard for construction along the Gulf Coast in close proximity to the system.

Overview of the South Louisiana Basin

The LOU System is supplied by natural gas produced onshore from the South Louisiana basin. With the strategic location of these assets in Louisiana, this system has access to the Henry Hub, the largest natural gas hub in the United States, and a substantial NGL distribution system with access to attractive markets throughout Louisiana and the southeast U.S. The south Louisiana area is characterized by medium-lived multi-horizon oil and gas reserves produced from both depletion and water driven reservoirs that exhibit moderate natural production declines. Aggregate natural gas production from the south Louisiana area has been approximately 114,000 Bcf over the life of the basin, and current production is approximately 2.0 Bcf/d. On average, the natural gas the system gathers and processes from south Louisiana contains approximately 2.7 gallons of NGLs per thousand cubic feet of natural gas. Also consistent with the Permian Basin, the characteristics of the south Louisiana area provide for an attractive natural gas gathering and processing environment.

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 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. In addition to timely connections and competitive pricing, a major competitive advantage for the LOU System is that the processing efficiencies are greater than those associated with many of its competitors. For the industrial customers in the Lake Charles Market, the primary competitors include GulfSouth 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.

Customers and Contracts

The North Texas System. The North Texas System gathers and processes natural gas for approximately 420 customers. For the year ended December 31, 2006 and the six months ended June 30, 2007, no customer, other than ConocoPhillips, represented more than 10% of the North Texas System's 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. For the six months ended June 30, 2007, the SAOU System's primary customers include Range Production Company, TXP, Inc. and Chevron. No other customer represented more than 10% of the SAOU System's volumes. The producer contracts under which the SAOU System operates are almost fully percent-of-proceeds based contracts with very little residual wellhead purchase or keep whole contract structures 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. For the six months ended June 30, 2007, the LOU System's primary producer customers include Murphy Gas Gathering Inc., Anadarko Petroleum Corporation and Cimarex Energy Co. No producer represented more than 10% of the LOU System's volumes. The LOU System's producer contract mix is primarily percent-of-liquids (approximately 63% by volume) and to a lesser extent short term wellhead purchase and keep whole contracts (approximately 37% by volume). 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 sometimes renegotiate, essentially all of these contracts.

The Combined Systems. After giving effect to the acquisition of the Acquired Businesses, our aggregate gas supply contract profile for the first half of 2007 would be approximately 82% percent-of-proceeds, approximately 1% fee and approximately 17% wellhead purchase/keep whole contracts, on a volume basis. 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 supplier for the years ended December 31, 2006 and 2005 was ConocoPhillips, who accounted for approximately 12.5% and 13.3%, respectively, of our supply, after giving effect to the acquisition of the Acquired Businesses. 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. As discussed above, our experience is that we retain, and sometimes renegotiate, essentially all of the contracts that fall in the evergreen category.

Safety and Maintenance Regulation

We are subject to regulation by the United States Department of Transportation, referred to as DOT, under the Accountable Pipeline and Safety Partnership Act of 1996, referred to as the Hazardous Liquid Pipeline Safety Act, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. The Hazardous Liquid Pipeline Safety Act covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in material compliance with these Hazardous Liquid Pipeline Safety Act regulations.

We are also subject to the Natural Gas Pipeline Safety Act of 1968, referred to as NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States oil and natural gas transportation pipelines and some gathering lines in high-consequence areas within 10 years. The DOT has developed regulations implementing the Pipeline Safety Improvement Act that will require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property. We currently estimate we will incur costs of approximately $1 million between 2007 and 2010 to implement integrity management program testing along certain segments of our natural gas pipelines owned by the North Texas System and the Acquired Businesses. This 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.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, states vary considerably in their authority and capacity to address pipeline safety. We do not anticipate any significant problems in complying with applicable state laws and regulations. Our natural gas pipelines have continuous inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements. We or the entities in which we own an interest inspect the pipelines regularly using equipment rented from third-party suppliers. Third parties also assist us in interpreting the results of the inspections.

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

Regulation of Operations

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

Gathering Pipeline Regulation

Section 1(b) of the Natural Gas Act of 1938, or 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. State regulation of gathering facilities generally includes various safety, environmental, nondiscriminatory take, and common purchaser requirements, and complaint-based rate regulation. 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.

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 source of supply. 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.

During the 2007 legislative session, the Texas State Legislature passed H.B. 3273, or Competition Bill, and H.B. 1920, or LUG Bill. The Competition Bill gives the Railroad Commission of Texas, or 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 gathering and transportation operations.

Intrastate Transportation Pipeline Regulation

Our subsidiary, Targa Intrastate Pipeline Company LLC, or Targa Intrastate, owns and operates a 41-mile, 6-inch diameter intrastate pipeline that transports natural gas from our Shackelford processing plant to an interconnect with Atmos-Texas. 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. The LOU System includes a Louisiana pipeline that receives all of the natural gas it transports within or at the boundary of the State of Louisiana for delivery within Louisiana, and is exempt from FERC regulation as a Hinshaw pipeline under Section 1(c) of the NGA. These natural gas transportation pipeline operations are not subject to rate regulation by FERC, but they are subject to regulation at the state level.

Like our gas gathering operations, our intrastate transportation operations are subject to ratable take and common purchaser statutes in the states in which we operate. The rates we charge for intrastate services are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us or whether the state regulatory agencies will change their regulation of those rates. 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 Texas Competition Bill and LUG Bill 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 transportation operations.

Processing Plants

The price we charge for processing services at our processing facilities is currently not subject to federal or state regulation. 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 and, if a complaint is filed, state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to our processing operations.

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, or the CFTC.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005, or EPAct 2005. Among other matters, EPAct 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of EPAct 2005, and subsequently denied rehearing. The rules make it unlawful for any entity, directly or indirectly: (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, 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 rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as service pursuant to Section 311 of the Natural Gas Policy Act of 1978, or NGPA, as well as otherwise non-jurisdictional entities, such as our operations, to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering. EPAct 2005 also amends the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes up to $1,000,000 per day per violation for violations occurring after August 8, 2005. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. FERC and CFTC hold substantial enforcement authority under the anti-market manipulation laws and regulations. Should we fail to comply with all applicable FERC-administered statutes, rule, regulations and orders, we could be subject to substantial penalties and fines. We could also be subject to related third party damage claims by, among others, market participants, 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. The 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 companies with whom we compete.

The anti-manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. The natural gas industry historically has been heavily regulated. Accordingly, we cannot assure you that present policies pursued by FERC and Congress will continue.

FERC Standards of Conduct for Transmission Providers

Commencing in 2003, FERC issued a series of orders adopting rules for new Standards of Conduct for Transmission Providers (Order No. 2004) which applied to interstate natural gas pipelines and to certain natural gas storage companies which provide storage services in interstate commerce. Order No. 2004 became effective in 2004. Among other matters, Order No. 2004 required interstate pipelines to operate independently from their energy affiliates, prohibited interstate pipelines from providing non-public transportation or shipper information to their energy affiliates, prohibited interstate pipelines from favoring their energy affiliates in providing service, and obligated interstate pipelines to post on their websites a number of items of information concerning the company, including its organizational structure, facilities shared with energy affiliates, discounts given for service and instances in which the company has agreed to waive discretionary terms of its tariff.

Late in 2006, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded Order No. 2004, as it relates to natural gas transportation providers. The court objected to FERC's expansion of the prior standards of conduct to include energy affiliates, and vacated the entire rule as it relates to natural gas transportation providers. On January 9, 2007, and as clarified on March 21, 2007, FERC issued an interim rule re-promulgating on an interim basis the standards of conduct that were not challenged before the court, while FERC decides how to respond to the court's decision on a permanent basis. The interim rule makes the standards of conduct apply to the relationship between natural gas transportation providers and their marketing affiliates, but not to energy affiliates who are not also marketing affiliates. Several companies requested rehearing and clarification of the interim rule. The March 21, 2007 order on clarification granted some of the requested clarifications and stated that it would address the other requests in its proceeding establishing a permanent rule. FERC has issued a notice of proposed rulemaking, or NOPR, that proposes permanent standards of conduct that FERC states will avoid the aspects of the previous standards of conduct rejected by the court. With respect to natural gas transportation providers, the NOPR proposes (1) that the permanent standards of conduct apply only to the relationship between natural gas transportation providers and their marketing affiliates, and (2) to make permanent the changes adopted in the interim rule permitting risk management employees to be shared by natural gas transportation providers and their marketing affiliates and requiring that tariff waivers be maintained in a written waiver log and available upon request. While our operations are not currently affected by the interim rules, we have no way to predict with certainty the scope of FERC's permanent rules on the standards of conduct.

FERC Market Transparency Notice of Proposed Rulemaking

On April 19, 2007, FERC issued a notice of proposed rulemaking in which it proposed to require intrastate natural gas pipelines, which may include both gathering and transportation pipelines, to post daily on the Internet the 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 total volume of their transactions. FERC has asserted that is has the jurisdiction to issue these regulations with respect to intrastate pipelines and otherwise non-jurisdictional buyers and sellers 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 EPAct 2005. Initial comments were submitted on July 11, 2007, and reply comments were submitted on August 23, 2007, by industry participants. FERC has not yet issued a final rule. If adopted as proposed, our intrastate natural gas operations may incur additional costs in order to comply with the posting and reporting requirements of the rules. We cannot predict the ultimate impact of these regulatory changes to our natural gas operations, and we do not believe that we would be affected by any such FERC action materially differently than other operators of natural gas gathering and intrastate transportation pipelines with whom we compete.

Environmental Matters

General

Our operation of pipelines, plants and other facilities for gathering, treating, transporting or processing natural gas, NGLs and other products is 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. 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 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.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat, process and fractionate natural gas. We cannot assure you, however, that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

Hazardous Substances and Waste

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances or solid and hazardous wastes (including petroleum hydrocarbons). These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste, and may impose strict, joint and several liability for the investigation and remediation of areas, at a facility where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, referred to as 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 that contributed to 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 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 U.S. Environmental Protection Agency, or 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 hazardous substances or other pollutants released into the environment. Despite the “petroleum exclusion” of CERCLA Section 101(14) that currently encompasses natural gas, we may nonetheless handle “hazardous substances” within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations 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, referred to as 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 our predecessor has 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

Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we 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 air permits containing various emissions and operational limitations, and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, restrictions on operations, and potentially criminal enforcement actions. We believe that we are in substantial compliance with these requirements. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

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 U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states, not including Texas, 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. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in *Massachusetts* that greenhouse gases fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we conduct business could adversely affect our operations and demand for our services.

Water Discharges

The Federal Water Pollution Control Act, also referred to as the 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.

Endangered Species Act

The federal Endangered Species Act, or 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.

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. We, or our predecessors, have leased these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title 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 initially 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 880 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.

Legal Proceedings

We are not a party to any legal proceeding 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 "— Regulation of Operations — Intrastate Natural Gas Pipeline Regulation" and "— Environmental Matters."

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 Targa Texas, and two 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 SAOU System and its successful acquisition of those assets in 2004. On October 2, 2007, the court granted defendants' motion for summary judgment. It is unknown at this time whether plaintiff will seek an appeal. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit.

MANAGEMENT

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 oversees our operations. Our general partner has seven directors. Targa elects all members to the board of directors of our general partner which 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.

In addition, our general partner has an audit committee of at least three directors who meet the independence and experience standards established by The NASDAQ Stock Market LLC and the Securities Exchange Act of 1934, as amended. Messrs. Evans, Pearl and Sullivan serve as the members 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 the 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 is given unrestricted access to the audit committee.

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

Three independent members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. Messrs. Evans, Pearl and Sullivan serve as the members of the conflicts committee. 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 Securities Exchange Act of 1934, as 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."

Directors and Executive Officers

The following table shows information regarding the current directors and executive officers of Targa Resources GP LLC. Directors are elected for one-year terms.

Name	Age(1)	Position with Targa Resources GP LLC
Rene R. Joyce	59	Chief Executive Officer and Director
Joe Bob Perkins	47	President
James W. Whalen	65	President — Finance and Administration and Director
Roy E. Johnson	62	Executive Vice President
Michael A. Heim	59	Executive Vice President and Chief Operating Officer
Jeffrey J. McParland	52	Executive Vice President and Chief Financial Officer
Paul W. Chung	47	Executive Vice President, General Counsel and Secretary
Peter R. Kagan	39	Director
Chansoo Joung	47	Director
Robert B. Evans	58	Director
Barry R. Pearl	58	Director
William D. Sullivan	51	Director

(1) As of August 31, 2007.

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. 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, or Shell, from 1998 through 1999, and President of energy services of Coral Energy Holding, L.P., or Coral, a subsidiary of Shell which was the gas and power marketing joint venture between Shell and Tejas Gas Corporation, or 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 was appointed as a director of our general partner on February 8, 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 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., or 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. Mr. McParland served as a director of our general partner between October 2006 and February 2007. Mr. McParland served as Treasurer of our general partner from October 2006 until May 2007, and he 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, 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 was appointed as a director of our general partner on February 8, 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 director of Antero Resources Corporation, Broad Oak Energy, Inc., Fairfield Energy Limited, MEG Energy Corp. and Universal Space Network, Inc.

Chansoo Joung was appointed as a director of our general partner on February 8, 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 Broad Oak Energy and Floridian Natural Gas Storage Company.

Robert B. Evans was appointed as a director of our general partner on February 8, 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 was appointed as a director of our general partner on February 8, 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 was appointed as a director of our general partner on February 8, 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

Our general partner will not receive any management fee or other compensation for its management of our partnership under the amended and restated omnibus agreement (the "Omnibus Agreement") with Targa or otherwise. Under the terms of the Omnibus Agreement, we will reimburse Targa up to $5 million annually for the provision of various general and administrative services for the North Texas System, subject to increases in the Consumer Price Index or as a result of an expansion of our operations. This limit on the amount of reimbursement will expire in 2010. In addition, we will reimburse Targa for the actual allocated costs, without limit, of providing various general and administrative services for the Acquired Businesses. Our obligation to reimburse Targa for operational expenses and certain direct expenses, including insurance coverage expense, relating to the North Texas System and the Acquired Businesses is not subject to a cap. The partnership agreement provides that our general partner will determine the expenses that are allocable to us. General and administrative costs will continue to be allocated to the Acquired Businesses according to Targa's allocation practice. Please see "Certain Relationships and Related Transactions — Omnibus Agreement."

Executive Compensation

Targa Resources GP LLC was formed on October 23, 2006. Accordingly, our general partner has not accrued any obligations with respect to management incentive or retirement benefits for its directors and officers for the 2004, 2005 or 2006 fiscal years. The compensation of the executive officers of Targa Resources GP LLC is set by Targa. The officers of our general partner and employees of Targa providing services to us are participating in employee benefit plans and arrangements sponsored by Targa. Targa Resources GP LLC has not entered into any employment agreements with any of its officers. The Compensation Committee of Targa Resources Investments Inc., or Targa Investments, has granted awards to Targa's key employees and the board of directors of our general partner has granted awards to our outside directors pursuant to the long-term incentive plans described below.

Director Compensation

The independent and non-management members of the board of directors of Targa Resources GP LLC receive an annual cash retainer of $34,000, an additional $1,500 for each board meeting attended and an additional $1,500 for each committee meeting attended ($750 if not at a regularly scheduled committee meeting held by teleconference). The chairman of Targa Resources GP LLC's audit committee receives an additional cash retainer of $20,000. Payment of director fees is generally made twice annually, at the second regularly scheduled meeting of the Board and the final meeting of the Board. Each member of the Board is reimbursed by us for out-of-pocket expenses in connection with attending meetings of the board or committees thereof.

Compensation Discussion and Analysis

We do not directly employ any of the persons responsible for managing our business and we do not have a compensation committee. Any compensation decisions that are required to be made by our general partner, Targa Resources GP LLC, will be made by its board of directors. All of our executive officers are employees of Targa Resources LLC, a wholly-owned subsidiary of Targa Resources, Inc., or Targa. All of the outstanding equity of Targa is held indirectly by Targa Investments. Our reimbursement for the compensation of executive officers will be 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 omnibus agreement.

During 2006, our executive officers were not specifically compensated for time expended with respect to our business or assets. Accordingly, we are not presenting any compensation for historical periods. For the fiscal year ending December 31, 2007, we currently expect that our Chief Executive Officer (our principal executive officer), our Chief Financial Officer (our principal financial officer) and three other persons (Messrs. Perkins, Whalen and Heim) constitute our most highly compensated executive officers (collectively, the "named executive officers"). The named executive officers will have substantially less than a majority of their compensation allocated to us. Compensation paid or awarded by us in 2007 with respect to our named executive officers will reflect only the portion of compensation paid by Targa Resources LLC that is allocated to us pursuant to Targa's allocation methodology and subject to the terms of the omnibus agreement. Targa Investments indirectly owns all of the outstanding equity of Targa and has ultimate decision making authority with respect to the compensation of our named executive officers. Under the terms of the Targa Investments stockholders' agreement, compensatory arrangements with 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 elements of compensation discussed below, and Targa Investments' decisions with respect to determinations on payments, will not be subject to approvals by the board of directors of our general partner. Awards under our long term incentive plan are made by the board of directors of our general partner with respect to grants to our independent and non-management directors and Targa's independent directors. Awards of cash-settled performance units to our executive officers are made by the Compensation Committee of Targa Investments pursuant to a separate plan adopted by Targa Investments, as described below.

With respect to compensation objectives and decisions regarding our named executive officers for 2007, the Compensation Committee of Targa Investments has approved the compensation of our named executive officers based on Targa Investments' business priorities, which have been used to develop performance based criteria for both discretionary cash awards and long-term incentive compensation. Targa Investments' senior management typically consults with compensation consultants and reviews market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, various relevant compensation surveys. Senior management then submits a proposal to Peter F. Kagan, a director and chairman of the Compensation Committee of Targa Investments, for the compensation to be paid or awarded to executives and employees. Mr. Kagan considers management's proposal (which he may request management to modify) and the resulting recommendation is then submitted to the Compensation Committee of Targa Investments for consideration. Targa Investments has consulted with compensation consultants with respect to determining 2007 compensation for the named executive officers and has established compensation criteria for the named executive officers as discussed above. All compensation determinations are discretionary and, as noted above, subject to Targa Investments' decision-making authority.

The elements of Targa Investments' compensation program discussed below are intended to provide a total incentive package designed to drive performance and reward contributions in support of the business strategies of Targa and its affiliates at the corporate, partnership and individual levels.

The primary elements of Targa Investments' compensation program are a combination of annual cash and long-term equity-based compensation. For 2007, elements of compensation for our named executive officers are the following:

- annual base salary;
- discretionary annual cash awards;
- performance awards under Targa's long-term incentive plan;
- Targa's contributions under its 401(k) and profit sharing plan; and
- Targa's other benefit plans on the same basis as all other Targa employees.

As discussed above, the portion of 2007 base salaries paid by Targa Resources LLC allocable to us and reported as compensation to our named executive officers by us will be based on Targa's methodology used for allocating general and administration expenses, subject to the limitations in the omnibus agreement. Targa Investments has established these salaries based on historical salaries paid to our named executive officers for services rendered to Targa, the extent of their equity ownership in Targa, market data and responsibilities of our named executive officers that may or may not be related to our business.

The discretionary cash awards for each of the named executive officers paid in 2007 for services to Targa and its affiliates during 2006, were determined by Targa Investments. The cash awards, in combination with base salaries and long-term incentive awards, are intended to yield competitive total cash compensation levels for the executive officers and drive performance in support of Targa's business strategies as well as our own. The portion of any discretionary cash awards paid by Targa Resources LLC allocable to us will be based on Targa's methodology used for allocating general and administrative expenses, subject to the limitations in the omnibus agreement. It is Targa Investments' general policy to pay these awards during the first quarter.

In connection with our initial public offering, Targa Investments issued to our executive officers cash-settled performance unit awards linked to the performance of our common units that will vest in August of 2010, with the amounts vesting under such awards dependent on our performance compared to a peer-group consisting of us and 12 other publicly traded partnerships. These performance unit awards are made pursuant to a plan adopted by Targa Investments and administered by Targa Resources LLC. The cost of such awards will be allocated to us pursuant to Targa's allocation methodology and subject to the terms of the omnibus agreement. Targa Investments' Compensation Committee has the ability to modify the peer-group in the event a peer company is no longer determined to be one of our peers. The cash settlement value of each performance unit award will be the value of an equivalent common unit at the time of vesting plus associated distributions over the vesting period, which may be higher or lower than our common unit price at the time of the award. If our performance equals or exceeds the performance for the median of the group, 100% of the award will vest. If we rank 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. Our named executive officers received an initial award of performance units as follows: 15,000 performance units to Mr. Joyce, 10,800 performance units to Mr. Perkins, 10,800 performance units to Mr. Whalen, 10,000 performance units to Mr. Heim and 8,200 performance units to Mr. McParland.

The equity-based awards we made in connection with our initial public offering to each of our non-management and independent directors under our long-term incentive plan were determined by Targa Investments and approved by the board of directors of our general partner. Each of these directors received an initial award of 2,000 restricted units. The awards to our independent and non-management directors consist of restricted units and will settle with the delivery of common units. We have made similar grants under our long-term incentive plan to the independent directors of Targa Resources, Inc. All of these awards are subject to three year vesting, without a performance condition, and vest ratably on each anniversary of the grant.

The equity-based awards to both our named executive officers and the directors of our general partner are intended to align their long-term interests with those of our unitholders. As discussed above, a portion of the equity-based awards granted to our named executive officers have been allocated to us, and a portion of any future awards under the Targa plan will be allocable to us in accordance with the allocation of general and administrative expenses pursuant to the omnibus agreement. Initially, officers and employees of Targa will participate in the Targa plan and the independent and non-management directors of our general partner and the independent directors of Targa Investments will participate in our plan. Over time, employees of Targa may begin to participate in our plan.

Our named executive officers are also owners of 13.5% of the fully diluted equity of Targa Investments. This equity was received through a combination of investment and equity grants. Targa Resources LLC generally does not pay for perquisites for any of our named executive officers, other than parking subsidies, and expects this policy to continue. Targa Resources LLC also makes contributions under its 401(k) plan for the benefit of our named executive officers in the same manner as for other Targa Resources LLC employees. It makes the following contributions to its plan for the benefit of employees: (i) 3% of the employee’s annual pay, (ii) an amount equal to the employee’s contributions to the plan up to 5% of the employee’s annual pay and (iii) a discretionary amount depending on Targa’s performance (2.25% of the employee’s pay for 2006).

Compensation Mix. We believe that each of the base salary, cash awards, and equity awards fit the overall compensation objectives of us and of Targa, as stated above, i.e., to provide competitive compensation opportunities to align and drive employee performance in support of Targa’s business strategies as well as our own and to attract, motivate and retain high quality talent with the skills and competencies required by Targa and us.

Long-Term Incentive Plan

General. Targa Resources GP LLC has adopted a long-term incentive plan, or the Plan, for employees, consultants and directors of Targa Resources GP LLC and its affiliates who perform services for us, including officers, directors and employees of Targa. The summary of the Plan contained herein does not purport to be complete and is qualified in its entirety by reference to the Plan. The Plan provides for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of distribution equivalent rights, or DERs. Subject to adjustment for certain events, an aggregate of 1,680,000 common units may be delivered pursuant to awards under the Plan. However, units that are cancelled, forfeited or are withheld to satisfy Targa Resources GP LLC’s tax withholding obligations or payment of an award’s exercise price are available for delivery pursuant to other awards. The Plan is administered by the board of directors of Targa Resources GP LLC. Administration of the Plan may be delegated to the compensation committee of the board of directors if one is established.

Restricted Units and Performance Units. A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the grantee receives a common unit that is not subject to forfeiture. A performance unit is a notional unit that entitles the grantee to receive upon the vesting of the performance unit cash equal to the fair market value of a common unit or, in the discretion of the board of directors, a common unit. The board of directors may make grants of restricted units and performance units under the Plan to eligible individuals containing such terms, consistent with the Plan, as the board of directors may determine, including the period over which restricted units and performance units granted will vest. The board of directors may, in its discretion, base vesting on the grantee’s completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, the restricted and performance units will vest automatically upon a change of control (as defined in the Plan) of us or our general partner, subject to any contrary provisions in the award agreement.

If a grantee’s employment, consulting or board membership terminates for any reason, the grantee’s restricted units and performance units will be automatically forfeited unless, and to the extent, the award agreement or the board of directors provides otherwise. Common units to be delivered with respect to these awards may be common units acquired by Targa Resources GP LLC in the open market, common units already owned by Targa Resources GP LLC, common units acquired by Targa Resources GP LLC directly from us or any other person, or any combination of the foregoing. Targa Resources GP LLC will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units with respect to these awards, the total number of common units outstanding will increase.

Distributions made by us with respect to awards of restricted units may, in the board of director's discretion, be subject to the same vesting requirements as the restricted units. The board of directors, in its discretion, may also grant tandem DERs with respect to performance units on such terms as it deems appropriate. DERs are rights that entitle the grantee to receive, with respect to a performance unit, cash equal to the cash distributions made by us on a common unit. However, DERs may be credited and paid in such other manner, including units, as the board of directors may provide.

We intend for the restricted units and performance units granted under the Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common units. Therefore, participants will not pay any consideration for the common units they receive with respect to these types of awards, and neither we nor our general partner will receive remuneration for the units delivered with respect to these awards.

Unit Options. The Plan also permits the grant of options covering common units. Unit options may be granted to such eligible individuals and with such terms as the board of directors may determine, consistent with the Plan; however, a unit option must have an exercise price equal to the fair market value of a common unit on the date of grant.

Upon exercise of a unit option, Targa Resources GP LLC will acquire common units in the open market at a price equal to the prevailing price on the principal national securities exchange upon which our common units are then traded, or directly from us or any other person, or use common units already owned by the general partner, or any combination of the foregoing. Targa Resources GP LLC will be entitled to reimbursement by us for the difference between the cost incurred by Targa Resources GP LLC in acquiring the common units and the proceeds received by Targa Resources GP LLC from an optionee at the time of exercise. Thus, we will bear the cost of the unit options. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and Targa Resources GP LLC will remit the proceeds it received from the optionee upon exercise of the unit option to us.

Replacement Awards. The board of directors, in its discretion, may grant replacement awards to eligible individuals who, in connection with an acquisition made by us, Targa Resources GP LLC or an affiliate, have forfeited an equity-based award in their former employer. A replacement award that is an option may have an exercise price less than the value of a common unit on the date of grant of the award.

Termination of Long-Term Incentive Plan. Targa Resources GP LLC's board of directors, in its discretion, may terminate the Plan at any time with respect to the common units for which a grant has not theretofore been made. The Plan will automatically terminate on the earlier of the 10th anniversary of the date it was initially approved by our unitholders or when common units are no longer available for delivery pursuant to awards under the Plan. Targa Resources GP LLC's board of directors will also have the right to alter or amend the Plan or any part of it from time to time and the board of directors may amend any award; provided, however, that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant. Subject to unitholder approval, if required by the rules of the principal national securities exchange upon which our common units are traded, the board of directors of Targa Resources GP LLC may increase the number of common units that may be delivered with respect to awards under the Plan.

Targa Long-Term Incentive Plan

As discussed above, Targa Investments has adopted a long term incentive plan for employees, consultants and directors of Targa Investments and its affiliates. The Targa plan provides for the grant of phantom units which are cash-settled performance unit awards linked to the performance of our common units.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table presents the beneficial ownership of certain unitholders prior to this offering and is based on reports filed with the Commission and the Partnership's records and sets forth the beneficial ownership of our units held by:

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

						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 Stock	Percentage of Series B Preferred Stock Beneficially Owned	Percentage of Restricted Stock Beneficially Owned
Targa Resources Investments Inc.(2)	—	*	11,528,231	100%	37.35%	—	—	—	—
Lehman Brothers Holdings Inc.(3)	1,775,219	9.18%	—	—	5.75%	—	—	—	—
Rene R. Joyce	20,000	*	223,648	1.94%	*	56,208	825,425	*	11.2%
Joe Bob Perkins	7,100	*	190,216	1.65%	*	47,632	701,554	*	9.5%
Michael A. Heim	2,500	*	176,382	1.53%	*	39,192	701,554	*	9.5%
Jeffrey J. McParland	1,500	*	154,478	1.34%	*	32,856	629,547	*	8.5%
James W. Whalen	35,700	*	151,020	1.31%	*	14,978	536,386	*	7.3%
Peter R. Kagan(4)	2,000	*	—	*	*	—	—	—	—
Chansoo Joung(5)	2,000	*	—	*	*	—	—	—	—
Robert B. Evans	3,900	*	—	*	*	—	—	—	—
Barry R. Pearl	4,300	*	—	*	*	—	—	—	—
William D. Sullivan	6,700	*	—	*	*	—	—	—	—
All directors and executive officers as a group (12 persons)	85,700	*	1,226,604	10.64%	4.25%	241,114	4,681,106	3.8%	63.3%

* 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) 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. Peter R. Kagan, one of our directors, is a general partner of WP and a Managing Director and member of WP LLC. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members of WP LLC and may be deemed to control the Warburg Pincus entities.

Messrs. Kagan, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.

(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, one of our directors, is a general partner of WP. Mr. Joung disclaims beneficial ownership of all shares held by the Warburg Pincus entities. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members of WP LLC and may be deemed to control the Warburg Pincus entities. Messrs. 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.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

After this offering, our general partner and its affiliates will own 11,528,231 subordinated units representing an aggregate 25.5% limited partner interest in us. In addition, our general partner will own 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 to be made by us to our general partner and its affiliates in connection with the ongoing operation and any liquidation of Targa Resources Partners LP. 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 affiliates of our general partner 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 \$1.2 million on their general partner units and \$15.6 million on their subordinated units.
Payments to our general partner and its affiliates	We will 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. Please see "The Partnership Agreement — Withdrawal or Removal of the General Partner."
	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 have entered into or will enter into the various documents and agreements that will effect the 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 this offering. These agreements will not be the result of arm's-length negotiations, and they, or any of the transactions that they provide for, may not be 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, will be paid from the proceeds of this 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 will acquire the Acquired Businesses 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 to terminate certain out of the money NGL hedges associated with the Acquired Businesses and to enter into new hedges for approximately the same volume and term at then current market prices. Pursuant to the Purchase Agreement, these hedging transactions will result in a $24.2 million increase to the purchase price we will pay to Targa for the Acquired Businesses. Pursuant to the Purchase Agreement, Targa has 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 Acquired Businesses) 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.

Omnibus Agreement

Concurrently with the closing of the acquisition of the Acquired Businesses, we will amend and restate 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 expenses, which are not subject to the $5 million cap for general and administrative expenses.

With respect to the Acquired Businesses, we will reimburse Targa for the following expenses:

- general and administrative expenses, which are not capped, allocated to the Acquired Businesses 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 Acquired Businesses 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 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 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 Acquired Businesses. 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 Acquired Businesses 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 Acquired Businesses' natural gas sales to third parties under contracts that remain in the name of the Acquired Businesses.

CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

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.

Conflicts of interest could arise in the situations described below, among others.

Targa is not limited in its ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses which in turn could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither our partnership agreement nor the omnibus agreement between us and Targa will prohibit 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 these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and cash available for distribution.

Neither our partnership agreement nor any other agreement requires Targa to pursue a business strategy that favors us or utilizes our assets or dictates what markets to pursue or grow. Targa's directors have a fiduciary duty to make these decisions in the best interests of the owners of Targa, which may be contrary to our interests.

Because certain of the directors of our general partner are also directors and/or officers of Targa, such directors have fiduciary duties to Targa that may cause them to pursue business strategies that disproportionately benefit Targa or which otherwise are not in our best interests.

Our general partner is allowed to take into account the interests of parties other than us, such as Targa, in resolving conflicts of interest.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. 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.

We have no employees and rely on the employees of Targa and its affiliates.

All of our executive management personnel are employees of Targa and devote a portion of their time to our business and affairs. We also utilize a significant number of employees of Targa to operate our business and provide us with general and administrative services for which we reimburse Targa for allocated expenses of operational personnel who perform services for our benefit and we reimburse Targa for allocated general and administrative expenses. Affiliates of our general partner and Targa also conduct businesses and activities of their own in which we have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the officers and employees who provide services to Targa.

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.

Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, 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. Examples include:
  - — the exercise of its right to reset the target distribution levels of its incentive distribution rights at higher levels and receive, in connection with this reset, a number of Class B units that are convertible at any time following the first anniversary of the issuance of these Class B units into common units;
  - — its limited call right;
  - — its rights to vote and transfer the units it owns;
  - — its registration rights; and
  - — its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement;

- provides that our general partner will 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 will not be 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 will be presumed that in making its decision the general partner or the conflicts committee 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.

If you purchase any common units, you will agree to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval or with respect to which our general partner has sought conflicts committee approval, on such terms as it determines to be necessary or appropriate to conduct our business including, but not limited to, the following:

- the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible into our securities, and the incurring of any other obligations;
- the purchase, sale or other acquisition or disposition of our securities, or the issuance of additional options, rights, warrants and appreciation rights relating to our securities;
- the mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets;
- the negotiation, execution and performance of any contracts, conveyances or other instruments;
- the distribution of our cash;
- the selection and dismissal of employees and agents, outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;
- the maintenance of insurance for our benefit and the benefit of our partners;
- the formation of, or acquisition of an interest in, the contribution of property to, and the making of loans to, any limited or general partnerships, joint ventures, corporations, limited liability companies or other relationships;
- the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity and otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense and the settlement of claims and litigation;

- the indemnification of any person against liabilities and contingencies to the extent permitted by law;
- the making of tax, regulatory and other filings, or rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets; and
- the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Our partnership agreement provides that our general partner must act in "good faith" when making decisions on our behalf, and our partnership agreement further provides that in order for a determination by our general partner to be made in "good faith," our general partner must believe that the determination is in our best interests. Please see "The Partnership Agreement — Voting Rights" for information regarding matters that require unitholder approval.

Our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, our general partner may use an amount equal to four times the amount needed to pay the minimum quarterly distribution on our units, which would not otherwise constitute available cash from operating surplus, in order to permit the payment of cash distributions on its units and incentive distribution rights. All of these actions may affect the amount of cash distributed to our unitholders and the general partner and may facilitate the conversion of subordinated units into common units. Please see "Our Cash Distribution Policy."

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by the general partner to our unitholders, including borrowings that have the purpose or effect of:

- enabling our general partner or its affiliates to receive distributions on any subordinated units held by them or the incentive distribution rights; or
- hastening the expiration of the subordination period.

For example, in the event we have not generated sufficient cash from our operations to pay the minimum quarterly distribution on our common units and our subordinated units, our partnership agreement permits us to borrow funds, which would enable us to make this distribution on all outstanding units. Please see "Our Cash Distribution Policy — Subordination Period."

Our partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us, our operating partnership, or its operating subsidiaries.

Our general partner determines which costs incurred by Targa are reimbursable by us.

We will reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. The partnership agreement provides that our general partner will determine the expenses that are allocable to us in good faith.

Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.

Our partnership agreement allows our general partner to determine, in good faith, any amounts to pay itself or its affiliates for any services rendered to us. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither our partnership agreement nor any of the other agreements, contracts or arrangements between us, on the one hand, and our general partner and its affiliates, on the other hand, are the result of arm's-length negotiations. Similarly, agreements, contracts or arrangements between us and our general partner and its affiliates that are entered into following the closing of this offering will not be required to be negotiated on an arm's-length basis, although, in some circumstances, our general partner may determine that the conflicts committee of our general partner may make a determination on our behalf with respect to one or more of these types of situations.

Our general partner will determine, in good faith, the terms of any of these transactions entered into after the sale of the common units offered in this offering.

Our general partner and its affiliates have no obligation to permit us to use any facilities or assets of our general partner or its affiliates, except as may be provided in contracts entered into specifically dealing with that use. There is no obligation of our general partner or its affiliates to enter into any contracts of this kind.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets, and not against our general partner or its assets. The partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of our common units.

Our general partner may exercise its right to call and purchase common units as provided in the partnership agreement or assign this right to one of its affiliates or to us. Our general partner is not bound by fiduciary duty restrictions in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please see "The Partnership Agreement — Limited Call Right."

Common unitholders have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us on the one hand, and our general partner and its affiliates, on the other, do not, and will not, grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

The attorneys, independent accountants and others who have performed services for us regarding this offering have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the conflicts committee and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases.

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 our unitholders. This ability may result in lower distributions to our common unitholders 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. 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 we are experiencing declines in our aggregate cash distributions or at a time when our general partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our general partner may be 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 specified priorities with respect to our distributions and which therefore may be more advantageous for the general partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then current business environment. 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. Please see "Our Cash Distribution Policy — General Partner Interest and Incentive Distribution Rights."

Fiduciary Duties

Our general partner is accountable to us and our unitholders as a fiduciary. Fiduciary duties owed to unitholders by our general partner are prescribed by law and the partnership agreement. The Delaware Revised Uniform Limited Partnership Act, which we refer to in this prospectus as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, modify, restrict or expand the fiduciary duties otherwise owed by a general partner to limited partners and the partnership.

Our partnership agreement contains various provisions modifying and restricting the fiduciary duties that might otherwise be owed by our general partner. We have adopted these restrictions to allow our general partner or its affiliates to engage in transactions with us that would otherwise be prohibited by state-law fiduciary duty standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. We believe this is appropriate and necessary because our general partner's board of directors has fiduciary duties to manage our general partner in a manner beneficial to its owners, as well as to you. Without these modifications, the general partner's ability to make decisions involving conflicts of interest would be restricted. The modifications to the fiduciary standards enable the general partner to take into consideration all parties involved in the proposed action, so long as the resolution is fair and reasonable to us. These modifications also enable our general partner to attract and retain experienced and capable directors. These modifications are detrimental to our common unitholders because they restrict the remedies available to unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interest. The following is a summary of the material restrictions of the fiduciary duties owed by our general partner to the limited partners:

State-law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally prohibit a general partner of a Delaware limited partnership from taking any action or engaging in any transaction where a conflict of interest is present. The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a third party where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.
Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues about compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in “good faith” and will not be subject to any other standard under applicable law. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any fiduciary obligation to us or the unitholders whatsoever. These standards reduce the obligations to which our general partner would otherwise be held. In addition to the other more specific provisions limiting the obligations of our general partner, our partnership agreement further provides that our general partner and the officers and directors of our general partner will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that the general partner or the officers and directors of our general partner acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the indemnitees’ conduct was unlawful.
Special provisions regarding affiliated transactions	Our partnership agreement generally provides that affiliated transactions and resolutions of conflicts of interest not involving a vote

of unitholders and that are not approved by the conflicts committee of the board of directors of our general partner must be:

- 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 between the parties involved (including other transactions that may be particularly favorable or advantageous to us).

If our general partner does not seek approval from the conflicts committee and the board of directors of our general partner 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 bullet points above, then it will be presumed that, in making its decision, the board of directors, which may include board members affected by the conflict of interest, 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. These standards reduce the obligations to which our general partner would otherwise be held.

By purchasing our common units, each common unitholder automatically agrees to be bound by the provisions in the partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner or assignee to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

We must indemnify our general partner and the officers, directors, managers of our general partner and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non- appealable judgment by a court of competent jurisdiction determining that these persons acted in bad faith or engaged in fraud or willful misconduct. We must also provide this indemnification for criminal proceedings unless our general partner or these other persons acted with knowledge that their conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act, in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. Please see "The Partnership Agreement — Indemnification."

DESCRIPTION OF OUR COMMON UNITS

The Units

Our common units and the subordinated units are separate classes of limited partner interests in us. The holders of units are entitled to participate in partnership distributions and exercise the rights or privileges available to limited partners under our partnership agreement. For a description of the relative rights and preferences of holders of common units and subordinated units in and to partnership distributions, please see this section and "Our Cash Distribution Policy." For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please see "The Partnership Agreement."

Transfer Agent and Registrar

Duties. Computershare Investor Services, LLC serves as registrar and transfer agent for our common units. We pay all fees charged by the transfer agent for transfers of common units except the following that must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a common unitholder; and
- other similar fees or charges.

There is no charge to unitholders for disbursements of our cash distributions. We have indemnified the transfer agent, its agents and each of their stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal. The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor has been appointed and has accepted the appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed, our partnership agreement; and
- gives the consents and approvals contained in our partnership agreement, such as the approval of all transactions and agreements that we are entering into in connection with our formation and this offering.

A transferee will become a substituted limited partner of our partnership for the transferred common units automatically upon the recording of the transfer on our books and records.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfers of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a substituted limited partner in our partnership for the transferred common units.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. We will provide prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to distributions of available cash, please see “Our Cash Distribution Policy”;
- with regard to the fiduciary duties of our general partner, please see “Conflicts of Interest and Fiduciary Duties”;
- with regard to the transfer of common units, please see “Description of our Common Units — Transfer of Common Units”; and
- with regard to allocations of taxable income and taxable loss, please see “Material Tax Consequences.”

Organization and Duration

Our partnership was organized on October 23, 2006 and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose under the partnership agreement is limited to any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law; provided, that our general partner shall not cause us to engage, directly or indirectly, in any business activity that the general partner determines would cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Although our general partner has the ability to cause us and our subsidiaries to engage in activities other than the business of gathering, compressing, treating, processing, transporting and selling natural gas and the business of transporting and selling NGLs, our general partner has no current plans to do so and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. Our general partner is authorized in general to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Power of Attorney

Each limited partner, and each person who acquires a unit from a unitholder, by accepting the common unit, automatically grants to our general partner and, if appointed, a liquidator, a power of attorney to, among other things, execute and file documents required for our qualification, continuance or dissolution. The power of attorney also grants our general partner the authority to amend, and to make consents and waivers under, our partnership agreement.

Cash Distributions

Our partnership agreement specifies the manner in which we make cash distributions to holders of our common units and other partnership securities as well as to our general partner in respect of its general partner interest and its incentive distribution rights. For a description of these cash distribution provisions, please see “Our Cash Distribution Policy.”

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under “— Limited Liability.”

Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2% general partner interest if we issue additional units. Our general partner's 2% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Our general partner will be entitled to make a capital contribution in order to maintain its 2% general partner interest in the form of the contribution to us of common units based on the current market value of the contributed common units.

Voting Rights

The following is a summary of the unitholder vote required for the matters specified below. Matters requiring the approval of a "unit majority" require:

- during the subordination period, the approval of a majority of our common units, excluding those common units held by our general partner and its affiliates, and a majority of the subordinated units, voting as separate classes; and
- after the subordination period, the approval of a majority of our common units and Class B units, if any, voting as a class.

In voting their common, Class B and subordinated units, our general partner and its affiliates will have no fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners.

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by the general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please see "— Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances. Please see "— Merger, Consolidation, Conversion, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority. Please see "— Termination and Dissolution."
Continuation of our business upon dissolution	Unit majority. Please see "— Termination and Dissolution."
Withdrawal of the general partner	Under most circumstances, the approval of a majority of our common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to December 31, 2016 in a manner that would cause a dissolution of our partnership. Please see "— Withdrawal or Removal of the General Partner."
Removal of the general partner	Not less than $66^{2}/_{3}$% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates. Please see "— Withdrawal or Removal of the General Partner."
Transfer of the general partner interest	Our general partner may transfer all, but not less than all, of its general partner interest in us without a vote of our unitholders to an affiliate or another person in connection with its merger or consolidation with or into, or sale of all or substantially all of its assets, to such person. The approval of a majority of our common units, excluding common units held by the general partner and its affiliates, is required in other circumstances for a transfer of the

	general partner interest to a third party prior to December 31, 2016. See "— Transfer of General Partner Units."
Transfer of incentive distribution rights	Except for transfers to an affiliate or another person as part of our general partner's merger or consolidation, sale of all or substantially all of its assets or the sale of all of the ownership interests in such holder, the approval of a majority of our common units, excluding common units held by the general partner and its affiliates, is required in most circumstances for a transfer of the incentive distribution rights to a third party prior to December 31, 2016. Please see "— Transfer of Incentive Distribution Rights."
Transfer of ownership interests in our general partner	No approval required at any time. Please see "— Transfer of Ownership Interests in the General Partner."

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of the partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. If it were determined, however, that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace the general partner;
- to approve some amendments to the partnership agreement; or
- to take other action under the partnership agreement;

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as the general partner. This liability would extend to persons who transact business with us who reasonably believe that the limited partner is a general partner. Neither the partnership agreement nor the Delaware Act specifically provides for legal recourse against the general partner if a limited partner were to lose limited liability through any fault of the general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Under the Delaware Act, a substituted limited partner of a limited partnership is liable for the obligations of his assignor to make contributions to the partnership, except that such person is not obligated for liabilities unknown to him at the time he became a limited partner and that could not be ascertained from the partnership agreement.

Our subsidiaries conduct business in Texas, although we may have subsidiaries that conduct business in other states in the future. Following our acquisition of the Acquired Businesses, our subsidiaries will conduct business in Louisiana and Texas. Maintenance of our limited liability as a limited partner of the operating partnership may require compliance with legal requirements in the jurisdictions in which the operating partnership conducts business, including qualifying our subsidiaries to do business there.

Limitations on the liability of limited partners for the obligations of a limited partner have not been clearly established in many jurisdictions. If, by virtue of our partnership interest in our operating partnership or otherwise, it were determined that we were conducting business in any state without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace the general partner, to approve some amendments to the partnership agreement, or to take other action under the partnership agreement constituted “participation in the control” of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as the general partner under the circumstances. We will operate in a manner that the general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Securities

Our partnership agreement authorizes us to issue an unlimited number of additional partnership securities for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units, subordinated units or other partnership securities. Holders of any additional common units we issue will be entitled to share equally with the then-existing holders of common units in our distributions of available cash. In addition, the issuance of additional common units or other partnership securities may dilute the value of the interests of the then-existing holders of common units in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership securities that, as determined by our general partner, may have special voting rights to which our common units are not entitled. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to our common units.

Upon the issuance of additional partnership securities, our general partner will be entitled, but not required, to make additional capital contributions to the extent necessary to maintain its 2% general partner interest in us. Our general partner’s 2% interest in us will be reduced if we issue additional units in the future (other than the issuance of common units upon exercise by the underwriters of the option to purchase additional common units, the issuance of units issued in connection with a reset of the incentive distribution target levels relating to our general partner’s incentive distribution rights or the issuance of units upon conversion of outstanding partnership securities) and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Moreover, our general partner will have the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, subordinated units or other partnership securities whenever, and on the same terms that, we issue those securities to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of the general partner and its affiliates, including such interest represented by common units and subordinated units, that existed immediately prior to each issuance. The holders of common units will not have preemptive rights to acquire additional common units or other partnership securities.

Amendment of the Partnership Agreement

General. Amendments to our partnership agreement may be proposed only by or with the consent of our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments. No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld at its option.

The provision of our partnership agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates). Upon completion of the offering, our general partner and its affiliates will own approximately 26.0% of the outstanding common and subordinated units.

No Unitholder Approval. Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner or assignee to reflect:

- a change in our name, the location of our principal place of our business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor the operating partnership nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- a change in our fiscal year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or the directors, officers, agents or trustees of our general partner from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our general partner determines to be necessary or appropriate for the authorization of additional partnership securities or rights to acquire partnership securities, including any amendment that our general partner determines is necessary or appropriate in connection with:
  - — the adjustments of the minimum quarterly distribution, first target distribution, second target distribution and third target distribution in connection with the reset of our general partner's incentive distribution rights as described under "Our Cash Distribution Policy — General Partner's Right to Reset Incentive Distribution Levels";
  - — the implementation of the provisions relating to our general partner's right to reset its incentive distribution rights in exchange for Class B units; or
  - — any modification of the incentive distribution rights made in connection with the issuance of additional partnership securities or rights to acquire partnership securities, provided that, any such modifications and related issuance of partnership securities have received approval by a majority of the members of the conflicts committee of our general partner;
- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;

- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect the limited partners (or any particular class of limited partners) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval. For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners or result in our being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes in connection with any of the amendments. No amendments to our partnership agreement other than those described above under "— No Unitholder Approval" will become effective without the approval of holders of at least 90% of the outstanding units voting as a single class unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that reduces the voting percentage required to take any action is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interest of us or the limited partners. Please see "Management — Management of Targa Resources Partners LP."

In addition, the partnership agreement generally prohibits our general partner without the prior approval of the holders of a unit majority, from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement, each of our units will be an identical unit of our partnership following the transaction, and the partnership securities to be issued do not exceed 20% of our outstanding partnership securities immediately prior to the transaction.

If the conditions specified in the partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide the limited partners and the general partner with the same rights and obligations as contained in the partnership agreement. The unitholders are not entitled to dissenters' rights of appraisal under the partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Termination and Dissolution

We will continue as a limited partnership until terminated under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or withdrawal or removal following approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability of any limited partner; and
- neither our partnership, our operating partnership nor any of our other subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless we are continued as a new limited partnership, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate to liquidate our assets and apply the proceeds of the liquidation as described in "Our Cash Distribution Policy — Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of the General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to December 31, 2016 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by the general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after December 31, 2016, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than the general partner and its affiliates. In addition, the partnership agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please see "— Transfer of General Partner Units" and "— Transfer of Incentive Distribution Rights."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority, voting as separate classes, may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please see "— Termination and Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than $66^2/_3$% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units and Class B units, if any, voting as a separate class, and subordinated units, voting as a separate class. The ownership of more than $33^1/_3$% of the outstanding units by our general partner and its affiliates would give them the practical ability to prevent our general partner's removal. At the closing of this offering, our general partner and its affiliates will own approximately 26.0% of the outstanding common and subordinated units.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by the general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end, and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;
- any existing arrearages in payment of the minimum quarterly distribution on our common units will be extinguished; and
- our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner and its incentive distribution rights for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner interest and its incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we are required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Transfer of General Partner Units

Except for transfer by our general partner of all, but not less than all, of its general partner units to:

- an affiliate of our general partner (other than an individual); or
- another entity as part of the merger or consolidation of our general partner with or into another entity or the transfer by our general partner of all or substantially all of its assets to another entity,

our general partner may not transfer all or any of its general partner units to another person prior to December 31, 2016 without the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. As a condition of this transfer, the transferee must assume, among other things, the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement, and furnish an opinion of counsel regarding limited liability and tax matters.

Our general partner and its affiliates may at any time, transfer units to one or more persons, without unitholder approval, except that they may not transfer subordinated units to us.

Transfer of Ownership Interests in the General Partner

At any time, Targa may sell or transfer all or part of their membership interests in our general partner to an affiliate or third party without the approval of our unitholders.

Transfer of Incentive Distribution Rights

Our general partner or its affiliates or a subsequent holder may transfer its incentive distribution rights to an affiliate of the holder (other than an individual) or another entity as part of the merger or consolidation of such holder with or into another entity, the sale of all of the ownership interest in the holder or the sale of all or substantially all of its assets to, that entity without the prior approval of the unitholders. Prior to December 31, 2016, other transfers of incentive distribution rights will require the affirmative vote of holders of a majority of the outstanding common units, excluding common units held by our general partner and its affiliates. On or after December 31, 2016, the incentive distribution rights will be freely transferable.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change the management of our general partner. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the prior approval of the board of directors of our general partner.

Our partnership agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal:

- the subordination period will end and all outstanding subordinated units will immediately convert into common units on a one-for-one basis;
- any existing arrearages in payment of the minimum quarterly distribution on our common units will be extinguished; and
- our general partner will have the right to convert its general partner units and its incentive distribution rights into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by either of our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the current market price as of the date three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please see "Material Tax Consequences — Disposition of Common Units."

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on the record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called represented in person or by proxy will constitute a quorum unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please see "— Issuance of Additional Securities." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Except as our partnership agreement otherwise provides, subordinated units will vote together with common units and Class B units as a single class.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record holders of common units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission is reflected in our books and records. Except as described under "— Limited Liability," the common units will be fully paid, and unitholders will not be required to make additional contributions.

Non-Citizen Assignees; Redemption

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, we may redeem the units held by the limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, the limited partner may be treated as a non-citizen assignee. A non-citizen assignee is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in-kind upon our liquidation.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of a general partner or any departing general partner;
- any person who is or was a director, officer, member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as director, officer, member, partner, fiduciary or trustee of another person at the request of our general partner, any departing general partner, an affiliate of our general partner or an affiliate of any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our general partner will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. The general partner is entitled to determine in good faith the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. The books are maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of common units, within 120 days after the close of each fiscal year, an annual report containing audited financial statements and a report on those financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 90 days after the close of each quarter.

We will furnish each record holder of a unit with information reasonably required for tax reporting purposes within 90 days after the close of each calendar year. This information will be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to unitholders will depend on the cooperation of unitholders in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and filing his federal and state income tax returns, regardless of whether he supplies us with information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each partner became a partner;
- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units, subordinated units or other partnership securities proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts and a structuring fee. Please see “Units Eligible for Future Sale.”

UNITS ELIGIBLE FOR FUTURE SALE

After the sale of our common units offered hereby, Targa and its affiliates will hold, directly and indirectly, an aggregate of 85,700 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 some may convert earlier. The sale of these units could have an adverse impact on the price of our common units or on any trading market that may develop.

Our common units sold in the offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units owned by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1% of the total number of the securities outstanding; or
- the average weekly reported trading volume of our common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned his common units for at least two years, would be entitled to sell common units under Rule 144 without regard to the public information requirements, volume limitations, manner of sale provisions and notice requirements of Rule 144.

The partnership agreement does not restrict our ability to issue any partnership securities at any time. Any issuance of additional common units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding. Please see "The Partnership Agreement — Issuance of Additional Securities."

Under our partnership agreement, our general partner and its affiliates have the right to cause us to register under the Securities Act and state securities laws the offer and sale of any common units, subordinated units or other partnership securities that they hold. Subject to the terms and conditions of our partnership agreement, these registration rights allow our general partner and its affiliates or their assignees holding any units or other partnership securities to require registration of any of these units or other partnership securities and to include them in a registration by us of other units, including units offered by us or by any unitholder. Our general partner will continue to have these registration rights for two years following its withdrawal or removal as our general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors and controlling persons from and against any liabilities under the Securities Act or any state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discounts and a structuring fee. Except as described below, our general partner and its affiliates may sell their units or other partnership interests in private transactions at any time, subject to compliance with applicable laws.

Targa, our partnership, our operating partnership, our general partner and the directors and executive officers of our general partner, have agreed not to sell any common units they beneficially own for a period of 90 days from the date of this prospectus. For a description of these lock-up provisions, please see "Underwriting."

MATERIAL TAX CONSEQUENCES

This section is a discussion of the material tax considerations that may be relevant to prospective unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Vinson & Elkins L.L.P., counsel to our general partner and us, insofar as it relates to legal conclusions with respect to matters of United States federal income tax law. This section is based upon current provisions of the Internal Revenue Code, existing and proposed regulations, current administrative rulings and court decisions, all of which are subject to change, and assumes completion of the acquisition of the Acquired Businesses. Later changes in these authorities may cause the tax consequences to vary substantially from the consequences described below. Unless the context otherwise requires, references in this section to “us” or “we” are references to Targa Resources Partners LP and our operating partnership.

The following discussion does not comment on all federal income tax matters affecting us or the unitholders. Moreover, the discussion focuses on unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, nonresident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), real estate investment trusts (REITs) or mutual funds. Accordingly, we urge each prospective unitholder to consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of common units.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Vinson & Elkins L.L.P. and are based on the accuracy of the representations made by us.

No ruling has been or will be requested from the IRS regarding any matter affecting us or prospective unitholders. Instead, we will rely on opinions of Vinson & Elkins L.L.P. Unlike a ruling, an opinion of counsel represents only that counsel’s best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for our common units and the prices at which common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders and our general partner and thus will be borne indirectly by our unitholders and our general partner. Furthermore, the tax treatment of us, or of an investment in us, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

For the reasons described below, Vinson & Elkins L.L.P. has not rendered an opinion with respect to the following specific federal income tax issues: (1) the treatment of a unitholder whose common units are loaned to a short seller to cover a short sale of common units (please see “— Tax Consequences of Unit Ownership — Treatment of Short Sales”); (2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please see “— Disposition of Common Units — Allocations Between Transferors and Transferees”); and (3) whether our method for depreciating Section 743 adjustments is sustainable in certain cases (please see “— Tax Consequences of Unit Ownership — Section 754 Election”).

Partnership Status

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss and deduction of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable unless the amount of cash distributed is in excess of the partner’s adjusted basis in his partnership interest.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to as the “Qualifying Income Exception,” exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of “qualifying income.” Qualifying income includes income and gains derived from the transportation, storage, processing and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. We estimate that less than 5% of our current gross income is not qualifying income; however, this estimate could change from time to time. Based upon and subject to this estimate, the factual representations made by us and the general partner and a review of the applicable legal authorities, Vinson & Elkins L.L.P. is of the opinion that at least 90% of our current gross income constitutes qualifying income.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to our status or the status of our operating partnership for federal income tax purposes or whether our operations generate "qualifying income" under Section 7704 of the Internal Revenue Code. Instead, we will rely on the opinion of Vinson & Elkins L.L.P. on such matters. It is the opinion of Vinson & Elkins L.L.P. that, based upon the Internal Revenue Code, its regulations, published revenue rulings and court decisions and the representations described below, we will be classified as a partnership and our operating partnership will be disregarded as an entity separate from us for federal income tax purposes.

In rendering its opinion, Vinson & Elkins L.L.P. has relied on factual representations made by us and our general partner. The representations made by us and our general partner upon which Vinson & Elkins L.L.P. has relied are:

(a) Neither we nor the operating partnership has elected or will elect to be treated as a corporation;

(b) For each taxable year, more than 90% of our gross income has been and will be income that Vinson & Elkins L.L.P. has opined or will opine is "qualifying income" within the meaning of Section 7704(d) of the Internal Revenue Code; and

(c) Each hedging transaction that we treat as resulting in qualifying income has been and will be appropriately identified as a hedging transaction pursuant to applicable Treasury Regulations, and has been and will be associated with oil, gas, or products thereof that are held or to be held by us in activities that Vinson & Elkins L.L.P. has opined or will opine result in qualifying income.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require us to make adjustments with respect to our unitholders or pay other amounts), we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in us. This deemed contribution and liquidation should be tax-free to unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were treated as an association taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to the unitholders, and our net income would be taxed to us at corporate rates. In addition, any distribution made to a unitholder would be treated as either taxable dividend income, to the extent of our current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the unitholder's tax basis in his common units, or taxable capital gain, after the unitholder's tax basis in his common units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the units.

The discussion below is based on Vinson & Elkins L.L.P.'s opinion that we will be classified as a partnership for federal income tax purposes.

Limited Partner Status

Unitholders who have become limited partners of Targa Resources Partners LP will be treated as partners of Targa Resources Partners LP for federal income tax purposes. Also, unitholders whose common units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their common units will be treated as partners of Targa Resources Partners LP for federal income tax purposes.

A beneficial owner of common units whose units have been transferred to a short seller to complete a short sale would appear to lose his status as a partner with respect to those units for federal income tax purposes. Please see "— Tax Consequences of Unit Ownership — Treatment of Short Sales."

Income, gain, deductions or losses would not appear to be reportable by a unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These holders are urged to consult their own tax advisors with respect to their tax consequences of holding common units in Targa Resources Partners LP.

The references to "unitholders" in the discussion that follows are to persons who are treated as partners in Targa Resources Partners LP for federal income tax purposes.

Tax Consequences of Unit Ownership

Flow-Through of Taxable Income. We will not pay any federal income tax. Instead, each unitholder will be required to report on his income tax return his share of our income, gains, losses and deductions without regard to whether corresponding cash distributions are received by him. Consequently, we may allocate income to a unitholder even if he has not received a cash distribution. Each unitholder will be required to include in income his allocable share of our income, gains, losses and deductions for our taxable year ending with or within his taxable year. Our taxable year ends on December 31.

Treatment of Distributions. Distributions by us to a unitholder generally will not be taxable to the unitholder for federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his common units immediately before the distribution. Our cash distributions in excess of a unitholder's tax basis generally will be considered to be gain from the sale or exchange of our common units, taxable in accordance with the rules described under "— Disposition of Common Units." Any reduction in a unitholder's share of our liabilities for which no partner, including the general partner, bears the economic risk of loss, known as "nonrecourse liabilities," will be treated as a distribution of cash to that unitholder. To the extent our distributions cause a unitholder's "at risk" amount to be less than zero at the end of any taxable year, he must recapture any losses deducted in previous years. Please see "— Limitations on Deductibility of Losses."

A decrease in a unitholder's percentage interest in us because of our issuance of additional common units will decrease his share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. A non-pro rata distribution of money or property may result in ordinary income to a unitholder, regardless of his tax basis in his common units, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation recapture, and/or substantially appreciated "inventory items," both as defined in the Internal Revenue Code, and collectively, "Section 751 Assets." To that extent, he will be treated as having been distributed his proportionate share of the Section 751 Assets and then having exchanged those assets with us in return for the non-pro rata portion of the actual distribution made to him. This latter deemed exchange will generally result in the unitholder's realization of ordinary income, which will equal the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis (generally zero) for the share of Section 751 Assets deemed relinquished in the exchange.

Ratio of Taxable Income to Distributions. We estimate that a purchaser of common units in this offering who owns those common units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2010, will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be 20% or less of the cash distributed with respect to that period. Thereafter, we anticipate that the ratio of allocable taxable income to cash distributions to the unitholders will increase. These estimates are based upon the assumption that gross income from operations will approximate the amount required to make the minimum quarterly distribution on all units and other assumptions with respect to capital expenditures, cash flow, net working capital, and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, competitive and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and with which the IRS could disagree. Accordingly, we cannot assure you that these estimates will prove to be correct. The actual percentage of distributions that will constitute taxable income could be higher or lower than our estimate and any differences could be material and could materially affect the value of our common units. For example, the ratio of allocable taxable income to cash distributions to a purchaser of common units in this offering will be greater, and perhaps substantially greater, than our estimate with respect to the period described above if:

- gross income from operations exceeds the amount required to make the minimum quarterly distribution on all units, yet we only distribute the minimum quarterly distribution on all units; or
- we make a future offering of common units and use the proceeds of the offering in a manner that does not produce substantial additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering.

Basis of Common Units. A unitholder's initial tax basis for his common units will be the amount he paid for our common units plus his share of our nonrecourse liabilities. That basis will be increased by his share of our income and by any increases in his share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by distributions from us, by the unitholder's share of our losses, by any decreases in his share of our nonrecourse liabilities and by his share of our expenditures that are not deductible in computing taxable income and are not required to be capitalized. A unitholder will have no share of our debt that is recourse to our general partner, but will have a share, generally based on his share of profits, of our nonrecourse liabilities. Please see "— Disposition of Common Units — Recognition of Gain or Loss."

Limitations on Deductibility of Losses. The deduction by a unitholder of his share of our losses will be limited to the tax basis in his units and, in the case of an individual unitholder, estate, trust, or corporate unitholder (if more than 50% of the value of the corporate unitholder's stock is owned directly or indirectly by or for five or fewer individuals) or some tax-exempt organizations, to the amount for which the unitholder is considered to be "at risk" with respect to our activities, if that is less than his tax basis. A common unitholder subject to these limitations must recapture losses deducted in previous years to the extent that distributions cause his at-risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his tax basis or at-risk amount, whichever is the limiting factor, is subsequently increased. Upon the taxable disposition of a unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at-risk limitation in excess of that gain would no longer be utilizable.

In general, a unitholder will be at risk to the extent of the tax basis of his units, excluding any portion of that basis attributable to his share of our nonrecourse liabilities, reduced by (i) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or other similar arrangement and (ii) any amount of money he borrows to acquire or hold his units, if the lender of those borrowed funds owns an interest in us, is related to the unitholder or can look only to the units for repayment. A unitholder's at-risk amount will increase or decrease as the tax basis of the unitholder's units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in his share of our nonrecourse liabilities.

In addition to the basis and at-risk limitations on the deductibility of losses, the passive loss limitations generally provide that individuals, estates, trusts and some closely-held corporations and personal service corporations can deduct losses from passive activities, which are generally trade or business activities in which the taxpayer does not materially participate, only to the extent of the taxpayer's income from those passive activities. The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will only be available to offset our passive income generated in the future and will not be available to offset income from other passive activities or investments, including our investments or investments in other publicly traded partnerships, or salary or active business income. Passive losses that are not deductible because they exceed a unitholder's share of income we generate may be deducted in full when he disposes of his entire investment in us in a fully taxable transaction with an unrelated party. The passive loss limitations are applied after other applicable limitations on deductions, including the at-risk rules and the basis limitation.

A unitholder's share of our net income may be offset by any of our suspended passive losses, but it may not be offset by any other current or carryover losses from other passive activities, including those attributable to other publicly traded partnerships.

Limitations on Interest Deductions. The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- our interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment. The IRS has indicated that the net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders. In addition, the unitholder's share of our portfolio income will be treated as investment income.

Entity-Level Collections. If we are required or elect under applicable law to pay any federal, state, local or foreign income tax on behalf of any unitholder or our general partner or any former unitholder, we are authorized to pay those taxes from our funds. That payment, if made, will be treated as a distribution of cash to the partner on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to all current unitholders. We are authorized to amend our partnership agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of units and to adjust later distributions, so that after giving effect to these distributions, the priority and characterization of distributions otherwise applicable under our partnership agreement is maintained as nearly as is practicable. Payments by us as described above could give rise to an overpayment of tax on behalf of an individual partner in which event the partner would be required to file a claim in order to obtain a credit or refund.

Allocation of Income, Gain, Loss and Deduction. In general, if we have a net profit, our items of income, gain, loss and deduction will be allocated among our general partner and the unitholders in accordance with their percentage interests in us. At any time that distributions are made to our common units in excess of distributions to the subordinated units, or incentive distributions are made to our general partner, gross income will be allocated to the recipients to the extent of these distributions. If we have a net loss, that loss will be allocated first to the general partner and the unitholders in accordance with their percentage interests in us to the extent of their positive capital accounts and, second, to the general partner.

Specified items of our income, gain, loss and deduction will be allocated to account for the difference between the tax basis and fair market value of our assets at the time of an offering, referred to in this discussion as “Contributed Property.” The effect of these allocations, referred to as Section 704(c) Allocations, to a unitholder purchasing common units from us in this offering will be essentially the same as if the tax basis of our assets were equal to their fair market value at the time of this offering. In the event we issue additional common units or engage in certain other transactions in the future “reverse Section 704(c) Allocations,” similar to the Section 704(c) Allocations described above, will be made to all holders of partnership interests, including purchasers of common units in this offering, to account for the difference between the “book” basis for purposes of maintaining capital accounts and the fair market value of all property held by us at the time of the future transaction. In addition, items of recapture income will be allocated to the extent possible to the partner who was allocated the deduction giving rise to the treatment of that gain as recapture income in order to minimize the recognition of ordinary income by some unitholders. Finally, although we do not expect that our operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of our income and gain will be allocated in an amount and manner as is needed to eliminate the negative balance as quickly as possible.

An allocation of items of our income, gain, loss or deduction, other than an allocation required by the Internal Revenue Code to eliminate the difference between a partner’s “book” capital account, credited with the fair market value of Contributed Property, and “tax” capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the “Book-Tax Disparity,” will generally be given effect for federal income tax purposes in determining a partner’s share of an item of income, gain, loss or deduction only if the allocation has substantial economic effect. In any other case, a partner’s share of an item will be determined on the basis of his interest in us, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to us;
- the interests of all the partners in profits and losses;
- the interest of all the partners in cash flow; and
- the rights of all the partners to distributions of capital upon liquidation.

Vinson & Elkins L.L.P. is of the opinion that, with the exception of the issues described in “— Section 754 Election” and “— Disposition of Common Units — Allocations Between Transferors and Transferees,” allocations under our partnership agreement will be given effect for federal income tax purposes in determining a partner’s share of an item of income, gain, loss or deduction.

Treatment of Short Sales. 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. As a result, during this period:

- any of our income, gain, loss or deduction with respect to those units would not be reportable by the unitholder;
- any cash distributions received by the unitholder as to those units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

Vinson & Elkins L.L.P. has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units. The IRS has announced that it is actively studying issues relating to the tax treatment of short sales of partnership interests. Please also read “— Disposition of Common Units — Recognition of Gain or Loss.”

Alternative Minimum Tax. Each unitholder will be required to take into account his distributive share of any items of our income, gain, loss or deduction for purposes of the alternative minimum tax. The current minimum tax rate for noncorporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income.

Prospective unitholders are urged to consult with their tax advisors as to the impact of an investment in units on their liability for the alternative minimum tax.

Tax Rates. In general, the highest effective United States federal income tax rate for individuals is currently 35% and the maximum United States federal income tax rate for net capital gains of an individual where the asset disposed of was held for more than twelve months at the time of disposition, is scheduled to remain at 15% for years 2008-2010 and then increase to 20% beginning January 1, 2011.

Section 754 Election. We will make the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election will generally permit us to adjust a common unit purchaser's tax basis in our assets ("inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price. This election does not apply to a person who purchases common units directly from us. The Section 743(b) adjustment belongs to the purchaser and not to other unitholders. For purposes of this discussion, a unitholder's inside basis in our assets will be considered to have two components: (1) his share of our tax basis in our assets ("common basis") and (2) his Section 743(b) adjustment to that basis.

Where the remedial allocation method is adopted (which we generally adopt as to all of our properties), the Treasury Regulations under Section 743 of the Internal Revenue Code require a portion of the Section 743(b) adjustment that is attributable to recovery property under Section 168 of the Internal Revenue Code whose book basis is in excess of its tax basis to be depreciated over the remaining cost recovery period for the Section 704(c) built in gain. Under Treasury Regulation Section 1.167(c)-1(a)(6), a Section 743(b) adjustment attributable to property subject to depreciation under Section 167 of the Internal Revenue Code, rather than cost recovery deductions under Section 168, is generally required to be depreciated using either the straight-line method or the 150% declining balance method. If we elect a method other than the remedial method, the depreciation and amortization methods and useful lives associated with the Section 743(b) adjustment, therefore, may differ from the methods and useful lives generally used to depreciate the inside basis in such properties. Under our partnership agreement, the general partner is authorized to take a position to preserve the uniformity of units even if that position is not consistent with these and any other Treasury Regulations. If we elect a method other than the remedial method with respect to a goodwill property, the common basis of such property is not amortizable. Please see "— Uniformity of Units."

Although Vinson & Elkins L.L.P. is unable to opine as to the validity of this approach because there is no direct or indirect controlling authority on this issue, we intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized Book-Tax Disparity, or treat that portion as non-amortizable to the extent attributable to property which is not amortizable. This method is consistent with the methods employed by other publicly traded partnerships but is arguably inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets. To the extent this Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may take a depreciation or amortization position under which all purchasers acquiring units in the same month would receive depreciation or amortization, whether attributable to common basis or a Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our assets. This kind of aggregate approach may result in lower annual depreciation or amortization deductions than would otherwise be allowable to some unitholders. Please see "— Uniformity of Units." A unitholder's tax basis for his common units is reduced by his share of our deductions (whether or not such deductions were claimed on an individual's income tax return) so that any position we take that understates deductions will overstate the common unitholder's basis in his common units, which may cause the unitholder to understate gain or overstate loss on any sale of such units. Please see "— Disposition of Common Units — Recognition of Gain or Loss." The IRS may challenge our position with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of the units. If such a challenge were sustained, the gain from the sale of units might be increased without the benefit of additional deductions.

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of our assets immediately prior to the transfer. In that case, as a result of the election, the transferee would have, among other items, a greater amount of depreciation and depletion deductions and his share of any gain or loss on a sale of our assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those units' share of the aggregate tax basis of our assets immediately prior to the transfer. Thus, the fair market value of the units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in us if we have a substantial built-in loss immediately after the transfer, or if we distribute property and have a substantial basis reduction. Generally a built-in loss or a basis reduction is substantial if it exceeds $250,000.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. For example, the allocation of the Section 743(b) adjustment among our assets must be made in accordance with the Internal Revenue Code. The IRS could seek to reallocate some or all of any Section 743(b) adjustment allocated by us to our tangible assets to goodwill instead. Goodwill, as an intangible asset, is generally nonamortizable or amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure you that the determinations we make will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than he would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year. We use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in income his share of our income, gain, loss and deduction for our taxable year ending within or with his taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his units following the close of our taxable year but before the close of his taxable year must include his share of our income, gain, loss and deduction in income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than one year of our income, gain, loss and deduction. Please see "— Disposition of Common Units — Allocations Between Transferors and Transferees."

Initial Tax Basis, Depreciation and Amortization. The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions and, ultimately, gain or loss on the disposition of these assets. The federal income tax burden associated with the difference between the fair market value of our assets and their tax basis immediately prior to this offering will be borne by our unitholders holding interests in us prior to this offering. Please see "— Tax Consequences of Unit Ownership — Allocation of Income, Gain, Loss and Deduction."

To the extent allowable, we may elect to use the depreciation and cost recovery methods that will result in the largest deductions being taken in the early years after assets subject to these allowances are placed in service. Because our general partner may determine not to adopt the remedial method of allocation with respect to any difference between the tax basis and the fair market value of goodwill immediately prior to this or any future offering, we may not be entitled to any amortization deductions with respect to any goodwill conveyed to us on formation or held by us at the time of any future offering. Please see "— Uniformity of Units." Property we subsequently acquire or construct may be depreciated using accelerated methods permitted by the Internal Revenue Code.

If we dispose of depreciable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation previously deducted and the nature of the property, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of his interest in us. Please see "— Tax Consequences of Unit Ownership — Allocation of Income, Gain, Loss and Deduction" and "— Disposition of Common Units — Recognition of Gain or Loss."

The costs we incur in selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. There are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us. The underwriting discounts and commissions we incur will be treated as syndication expenses.

Valuation and Tax Basis of Our Properties. The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values, and the initial tax bases, of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by unitholders might change, and unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Common Units

Recognition of Gain or Loss. Gain or loss will be recognized on a sale of units equal to the difference between the amount realized and the unitholder's tax basis for the units sold. A unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received by him plus his share of our nonrecourse liabilities. Because the amount realized includes a unitholder's share of our nonrecourse liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Prior distributions from us in excess of cumulative net taxable income for a common unit that decreased a unitholder's tax basis in that common unit will, in effect, become taxable income if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a unitholder, other than a "dealer" in units, on the sale or exchange of a unit held for more than one year will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of units held more than twelve months will generally be taxed at a maximum rate of 15%. However, a portion of this gain or loss, which will likely be substantial, will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to depreciation recapture or other "unrealized receivables" or to "inventory items" we own. The term "unrealized receivables" includes potential recapture items, including depreciation recapture. Ordinary income attributable to unrealized receivables, inventory items and depreciation recapture may exceed net taxable gain realized upon the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and a capital loss upon a sale of units. Net capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling unitholder who can identify common units transferred with an ascertainable holding period to elect to use the actual holding period of the common units transferred. Thus, according to the ruling, a common unitholder will be unable to select high or low basis common units to sell as would be the case with corporate stock, but, according to the regulations, may designate specific common units sold for purposes of determining the holding period of units transferred. A unitholder electing to use the actual holding period of common units transferred must consistently use that identification method for all subsequent sales or exchanges of common units. A unitholder considering the purchase of additional units or a sale of common units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees. In general, our taxable income and losses will be determined annually, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month, which we refer to in this prospectus as the "Allocation Date." However, gain or loss realized on a sale or other disposition of our assets other than in the ordinary course of business will be allocated among the unitholders on the Allocation Date in the month in which that gain or loss is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss and deduction realized after the date of transfer.

The use of this method may not be permitted under existing Treasury Regulations. Accordingly, Vinson & Elkins L.L.P. is unable to opine on the validity of this method of allocating income and deductions between unitholders. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the unitholder's interest, our taxable income or losses might be reallocated among the unitholders. We are authorized to revise our method of allocation between unitholders, as well as unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury Regulations.

A unitholder who owns units at any time during a quarter and who disposes of them prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deductions attributable to that quarter but will not be entitled to receive that cash distribution.

Notification Requirements. A unitholder who sells any of his units is generally required to notify us in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of units who purchases units from another unitholder is also generally required to notify us in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a purchase may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker who will satisfy such requirements.

Constructive Termination. We will be considered to have been terminated for 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.

A constructive termination results in the closing of our taxable year for all unitholders. 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 result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in us filing two tax returns (and common unitholders receiving two Schedule K-1s) for one fiscal year and the cost of the preparation of these returns will be borne by all common unitholders. We would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code, and a termination would result in a deferral of our deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Uniformity of Units

Because we cannot match transferors and transferees of units, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements, both statutory and regulatory. A lack of uniformity can result from a literal application of Treasury Regulation Section 1.167(c)-1(a)(6). Any non-uniformity could have a negative impact on the value of the units. Please see "— Tax Consequences of Unit Ownership — Section 754 Election."

We intend to depreciate the portion of a Section 743(b) adjustment attributable to unrealized appreciation in the value of Contributed Property, to the extent of any unamortized Book-Tax Disparity, using a rate of depreciation or amortization derived from the depreciation or amortization method and useful life applied to the property's unamortized book-tax disparity, or treat that portion as nonamortizable, to the extent attributable to property which is not amortizable, consistent with the regulations under Section 743 of the Internal Revenue Code, even though that position may be inconsistent with Treasury Regulation Section 1.167(c)-1(a)(6), which is not expected to directly apply to a material portion of our assets, and Treasury Regulation Section 1.197-2(g)(3). Please see "— Tax Consequences of Unit Ownership — Section 754 Election." To the extent that the Section 743(b) adjustment is attributable to appreciation in value in excess of the unamortized Book-Tax Disparity, we will apply the rules described in the Treasury Regulations and legislative history. If we determine that this position cannot reasonably be taken, we may adopt a depreciation and amortization position under which all purchasers acquiring units in the same month would receive depreciation and amortization deductions, whether attributable to a common basis or Section 743(b) adjustment, based upon the same applicable rate as if they had purchased a direct interest in our property. If this position is adopted, it may result in lower annual depreciation and amortization deductions than would otherwise be allowable to some unitholders and risk the loss of depreciation and amortization deductions not taken in the year that these deductions are otherwise allowable. This position will not be adopted if we determine that the loss of depreciation and amortization deductions will have a material adverse effect on the unitholders. If we choose not to utilize this aggregate method, we may use any other reasonable depreciation and amortization method to preserve the uniformity of the intrinsic tax characteristics of any units that would not have a material adverse effect on the unitholders. The IRS may challenge any method of depreciating the Section 743(b) adjustment described in this paragraph. If this challenge were sustained, the uniformity of units might be affected, and the gain from the sale of units might be increased without the benefit of additional deductions. Please see "— Disposition of Common Units — Recognition of Gain or Loss."

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations and other non-U.S. persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. Virtually all of our income allocated to a unitholder that is a tax-exempt organization will be unrelated business taxable income and will be taxable to them.

Non-resident aliens and foreign corporations, trusts or estates that own units will be considered to be engaged in business in the United States because of the ownership of units. As a consequence, they will be required to file federal tax returns to report their share of our income, gain, loss or deduction and pay federal income tax at regular rates on their share of our net income or gain. Moreover, under rules applicable to publicly traded partnerships, we will withhold at the highest applicable effective tax rate from cash distributions made quarterly to non-U.S. unitholders. Each non-U.S. unitholder must obtain a taxpayer identification number from the IRS and submit that number to our transfer agent on a Form W-8BEN or applicable substitute form in order to obtain credit for these withholding taxes. A change in applicable law may require us to change these procedures.

In addition, because a foreign corporation that owns units will be treated as engaged in a United States trade or business, that corporation may be subject to the United States branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain, as adjusted for changes in the foreign corporation's "U.S. net equity," which are effectively connected with the conduct of a United States trade or business. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Internal Revenue Code.

Under a ruling of the IRS, a non-U.S. unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized on the sale or disposition of that unit to the extent that this gain is effectively connected with a United States trade or business of the non-U.S. unitholder. Because a non-U.S. unitholder is considered to be engaged in business in the United States by virtue of the ownership of units, under this ruling a non-U.S. unitholder who sells or otherwise disposes of a unit generally will be subject to federal income tax on gain realized on the sale or disposition of units. Apart from the ruling, a non-U.S. unitholder will not be taxed or subject to withholding upon the sale or disposition of a unit if he has owned less than 5% in value of the units during the five-year period ending on the date of the disposition and if the units are regularly traded on an established securities market at the time of the sale or disposition.

Administrative Matters

Information Returns and Audit Procedures. We intend to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of our income, gain, loss and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss and deduction. We cannot assure you that those positions will in all cases yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither we nor Vinson & Elkins L.L.P. can assure prospective unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

The IRS may audit our federal income tax information returns. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a unitholder's return could result in adjustments not related to our returns as well as those related to our returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. Our partnership agreement names our general partner as our Tax Matters Partner.

The Tax Matters Partner will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting. Persons who hold an interest in us as a nominee for another person are required to furnish to us:

- the name, address and taxpayer identification number of the beneficial owner and the nominee;
- whether the beneficial owner is:
  - — a person that is not a United States person;
  - — a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or
  - — a tax-exempt entity;
- the amount and description of units held, acquired or transferred for the beneficial owner; and
- specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

For individuals, a substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000 ($10,000 for most corporations). The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

- for which there is, or was, “substantial authority”; or
- as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of unitholders might result in that kind of an “understatement” of income for which no “substantial authority” exists, we must disclose the pertinent facts on our return. In addition, we will make a reasonable effort to furnish sufficient information for unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit unitholders to avoid liability for this penalty. More stringent rules apply to “tax shelters,” which we do not believe includes us.

A substantial valuation misstatement exists if the value of any property, or the adjusted basis of any property, claimed on a tax return is 150% or more of the amount determined to be the correct amount of the valuation or adjusted basis. No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). If the valuation claimed on a return is 200% or more than the correct valuation, the penalty imposed increases to 40%.

Reportable Transactions. If we were to engage in a “reportable transaction,” we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a “listed transaction” or that it produces certain kinds of losses for partnerships, individuals, S corporations, and trusts in excess of $2 million in any single year, or $4 million in any combination of tax years. Our participation in a reportable transaction could increase the likelihood that our federal income tax information return (and possibly your tax return) would be audited by the IRS. Please see “— Information Returns and Audit Procedures.”

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, you may be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at “— Accuracy-Related Penalties,”
- for those persons otherwise entitled to deduct interest on federal tax deficiencies, nondeductibility of interest on any resulting tax liability and
- in the case of a listed transaction, an extended statute of limitations.

We do not expect to engage in any “reportable transactions.”

State, Local, Foreign and Other Tax Considerations

In addition to federal income taxes, you may be subject to other taxes, such as state, local and foreign income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property or in which you are a resident. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on his investment in us. We currently own property and do business in Texas and Louisiana. Currently, Texas does not impose a personal income tax on individuals but Louisiana does. Moreover, both states impose entity level taxes on corporations and other entities. Current law may change. Moreover, we may also own property or do business in other jurisdictions in the future. Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you might be required to file income tax returns and to pay income taxes in other jurisdictions in which we do business or own property, now or in the future, and may be subject to penalties for failure to comply with those requirements. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. Some jurisdictions may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the jurisdiction. Withholding, the amount of which may be greater or less than a particular unitholder’s income tax liability to the jurisdiction, generally does not relieve a nonresident unitholder from the obligation to file an income tax return. Amounts withheld will be treated as if distributed to unitholders for purposes of determining the amounts distributed by us. Please see “— Tax Consequences of Unit Ownership — Entity-Level Collections.” Based on current law and our estimate of our future operations, the general partner anticipates that any amounts required to be withheld will not be material.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of his investment in us. Accordingly, each prospective unitholder is urged to consult, and depend upon, his tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as United States federal tax returns, that may be required of him. Vinson & Elkins L.L.P. has not rendered an opinion on the state, local or foreign tax consequences of an investment in us.

INVESTMENT IN TARGA RESOURCES PARTNERS LP BY EMPLOYEE BENEFIT PLANS

An investment in us by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility provisions of ERISA and the prohibited transaction provisions of ERISA and the Internal Revenue Code. For these purposes the term “employee benefit plan” includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, Keogh plans, simplified employee pension plans and tax deferred annuities or IRAs established or maintained by an employer or employee organization. Among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA;
- whether in making the investment, that plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA; and
- whether the investment will result in recognition of unrelated business taxable income by the plan and, if so, the potential after-tax investment return. Please see “Material Tax Consequences — Tax-Exempt Organizations and Other Investors.”

The person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should determine whether an investment in us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit employee benefit plans, and also IRAs and certain other types of accounts (e.g., an Archer MSA) that are not considered part of an ERISA employee benefit plan, from engaging in specified transactions involving “plan assets” with parties that are “parties in interest” under ERISA or “disqualified persons” under the Internal Revenue Code with respect to the plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that the parties managing us would become ERISA fiduciaries of the investing plan and that our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed “plan assets” under some circumstances. Under these regulations, an entity’s assets would not be considered to be “plan assets” if, among other things:

(a) the equity interests acquired by employee benefit plans are publicly offered securities — i.e., the equity interests are part of a class of securities that is widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under certain provisions of the federal securities laws;

(b) the entity is an “operating company,” — i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority-owned subsidiary or subsidiaries; or

(c) there is no significant investment by benefit plan investors, which is defined to mean that less than 25% of the value of each class of equity interest is held by the employee benefit plans referred to above, IRAs and certain other plans not subject to ERISA (including governmental plans) and entities whose underlying assets include plan assets by reason of a plan’s investment in the entity.

Our assets should not be considered “plan assets” under these regulations because it is expected that the investment will satisfy the requirements in (a) above.

Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA and the Internal Revenue Code in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

UNDERWRITING

Citigroup Global Markets Inc., Lehman Brothers Inc. Goldman, Sachs & Co. and Merrill Lynch, Pierce, Fenner & Smith Incorporated are acting as joint bookrunning managers of the offering and representatives of the underwriters named below. Subject to the terms and conditions stated in the underwriting agreement dated the date of this prospectus, each underwriter named below has severally agreed to purchase, and we have agreed to sell to that underwriter, the number of units set forth opposite the underwriter's name.

Underwriter	Number of Common Units
Citigroup Global Markets Inc.	2,902,500
Lehman Brothers Inc.	2,902,500
Goldman, Sachs & Co.	1,822,500
Merrill Lynch, Pierce, Fenner & Smith Incorporated	1,822,500
UBS Securities LLC	810,000
Wachovia Capital Markets, LLC	810,000
Credit Suisse Securities (USA) LLC	810,000
Deutsche Bank Securities Inc.	810,000
Raymond James & Associates, Inc.	270,000
RBC Capital Markets Corporation	270,000
SMH Capital Inc.	270,000
Total	13,500,000

The underwriting agreement provides that the obligations of the underwriters to purchase the units included in this offering are subject to approval of legal matters by counsel and to other conditions. The underwriters are obligated to purchase all the units (other than those covered by their option to purchase additional units described below) if they purchase any of the units.

The underwriters propose to offer some of the units directly to the public at the public offering price set forth on the cover page of the prospectus and some of the units to dealers at the public offering price less a concession not to exceed $0.64 per unit. If all of the units are not sold at the initial offering price, the representatives may change the public offering price and the other selling terms.

We have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to 2,025,000 additional common units at the public offering price less the underwriting discount. The underwriters may exercise the option solely for the purpose of covering over-allotments, if any, in connection with this offering. To the extent the option is exercised, each underwriter must purchase a number of additional units approximately proportionate to that underwriter's initial purchase commitment.

We, our general partner, all of the officers and directors of our general partner and our principal beneficial unitholders have agreed that, for a period of 90 days from the date of this prospectus, we and they will not, without the prior written consent of Citigroup Global Markets Inc., dispose of or hedge any of our common units or any securities convertible into or exchangeable for our common units. Notwithstanding the foregoing, if (1) during the last 17 days of the 90-day period, we issue an earnings release or material news or a material event relating to us occurs; or (2) prior to the expiration of the 90-day restricted period, we announce that we will release earnings results during the 16-day period beginning on the last day of the 90-day period, the restrictions described above shall continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

Citigroup Global Markets Inc. in its sole discretion may release any of the securities subject to these lock-up agreements at any time without notice. Citigroup Global Markets Inc. has no present intent or arrangement to release any of the securities subject to these lock-up agreements. The release of any lock-up is considered on a case by case basis. Factors in deciding whether to release common units may include the length of time before the lock-up expires, the number of units involved, the reason for the requested release, market conditions, the trading price of our common units, historical trading volumes of our common units and whether the person seeking the release is an officer, director or affiliate of us.

Our common units are listed on The NASDAQ Stock Market LLC under the symbol "NGLS."

The following table shows the underwriting discounts and commissions that we are to pay to the underwriters in connection with this offering. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional common units.

	No Exercise	Full Exercise
Per unit	$ 1.074	$ 1.074
Total	$ 14,499,000	$ 16,673,850

We estimate that our portion of the total expenses of this offering, excluding underwriting discounts and commissions and net of a reimbursement of certain expenses by the underwriters in an amount equal to approximately $0.9 million, will be approximately $2.0 million.

In connection with the offering, the representatives on behalf of the underwriters, may purchase and sell common units in the open market. These transactions may include short sales, syndicate covering transactions and stabilizing transactions. Short sales involve syndicate sales of common units in excess of the number of units to be purchased by the underwriters in the offering, which creates a syndicate short position. "Covered" short sales are sales of units made in an amount up to the number of units represented by the underwriters' option to purchase additional common units. In determining the source of units to close out the covered syndicate short position, the underwriters will consider, among other things, the price of units available for purchase in the open market as compared to the price at which they may purchase units through their option to purchase additional common units. Transactions to close out the covered syndicate short position involve either purchases of the common units in the open market after the distribution has been completed or the exercise of their option to purchase additional common units. The underwriters may also make "naked" short sales of units in excess of their option to purchase additional common units. The underwriters must close out any naked short position by purchasing common units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the units in the open market after pricing that could adversely affect investors who purchase in the offering. Stabilizing transactions consist of bids for or purchases of units in the open market while the offering is in progress.

The underwriters also may impose a penalty bid. Penalty bids permit the underwriters to reclaim a selling concession from a syndicate member when an underwriter repurchases units originally sold by that syndicate member in order to cover syndicate short positions or make stabilizing purchases.

Any of these activities, as well as purchases by the underwriters for their own accounts, may have the effect of preventing or retarding a decline in the market price of the units. They may also cause the price of the units to be higher than the price that would otherwise exist in the open market in the absence of these transactions. The underwriters may conduct these transactions on The NASDAQ Stock Market LLC or otherwise. If the underwriters commence any of these transactions, they may discontinue them at any time. Prior to purchasing the common units being offered pursuant to this prospectus, one of the underwriters purchased, on behalf of the syndicate, 111,740 common units at an average price of $26.9314 per unit, in stabilizing transactions.

In addition, in connection with this offering, some of the underwriters may engage in passive market making transactions in the common units on The NASDAQ Stock Market LLC, prior to the pricing and completion of the offering. Passive market making consists of displaying bids on The NASDAQ Stock Market LLC no higher than the bid prices of independent market makers and making purchases at prices no higher than those independent bids and effected in response to order flow. Net purchases by a passive market maker on each day are limited to a specified percentage of the passive market maker's average daily trading volume in the common units during a specified period and must be discontinued when that limit is reached. Passive market making may cause the price of the common units to be higher than the price that otherwise would exist in the open market in the absence of those transactions. If the underwriters commence passive market making transactions, they may discontinue them at any time.

The underwriters have performed from time to time and are performing investment banking and advisory services for Targa and for us for which they have received and will receive customary fees and expenses. Affiliates of Merrill Lynch, Pierce, Fenner & Smith Incorporated own an approximate 6.5% fully diluted, indirect ownership interest in Targa. In addition, affiliates of Citigroup Global Markets Inc., Lehman Brothers Inc., Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, UBS Securities LLC, Wachovia Capital Markets, LLC, Credit Suisse Securities (USA) LLC and RBC Capital Markets Corporation are lenders under our credit facility and affiliates of certain of the underwriters, including Lehman Brothers Inc., Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wachovia Capital Markets, LLC, Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., are lenders under Targa's credit facility. We expect that a portion of Targa's credit facility will be repaid using the net proceeds from this offering that are paid to Targa. In addition, we expect that a portion of our credit facility will be repaid using the net proceeds from any exercise by the underwriters of the their option to purchase additional common units. Affiliates of some of the underwriters are lenders under Targa Investments' credit facility.

We have entered into swap transactions with affiliates of Goldman, Sachs & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Wachovia Capital Markets, LLC and Credit Suisse Securities (USA) LLC. For a description of these transactions, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Quantitative and Qualitative Disclosure about Market Risk — Commodity Price Risk." We have agreed to pay these counterparties a fee in an amount we believe to be customary in connection with these transactions. In addition, Lehman Brothers Inc. and its affiliates beneficially own an aggregate of approximately 1.8 million of our common units.

A prospectus in electronic format may be made available by one or more of the underwriters. The representatives may agree to allocate a number of units to underwriters for sale to their online brokerage account holders. The representatives will allocate units to underwriters that may make Internet distributions on the same basis as other allocations. In addition, units may be sold by the underwriters to securities dealers who resell units to online brokerage account holders.

Other than the prospectus in electronic format, the information on any underwriter's web site and any information contained in any other web site maintained by an underwriter is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or any underwriter in its capacity as an underwriter and should not be relied upon by investors.

We and our general partner have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments the underwriters may be required to make because of any of those liabilities.

Because the Financial Industry Regulatory Authority ("FINRA") views the units offered by this prospectus as interests in a direct participation program, the offering is being made in compliance with Rule 2810 of the FINRA's Conduct Rules. Investor suitability with respect to the units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

VALIDITY OF OUR COMMON UNITS

The validity of our common units will be passed upon for us by Vinson & Elkins L.L.P., Houston, Texas. Certain legal matters in connection with our common units offered hereby will be passed upon for the underwriters by Baker Botts L.L.P., Dallas, Texas. Baker Botts L.L.P. performs legal services for Targa and us from time to time on matters unrelated to this offering.

EXPERTS

The financial statements of Targa North Texas LP as of December 31, 2006 and 2005 and for the year ended December 31, 2006, and the two months ended December 31, 2005, included in this prospectus have been so included in reliance on the report (which contains an explanatory paragraph relating to significant transactions with related parties described in Note 9 to the financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of the North Texas System for the ten months ended October 31, 2005, and the year ended December 31, 2004 included in this prospectus have been so included in reliance on the report (which contains an explanatory paragraph relating to significant transactions with related parties described in Note 9 to the financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of the SAOU and LOU Systems of Targa Resources, Inc as of December 31, 2006 and 2005 and for each of the two years in the period ended December 31, 2006 included in this prospectus have been so included in reliance on the report (which contains an explanatory paragraph relating to significant transactions with related parties described in Note 7 to the financial statements) of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The financial statements of Targa Resources GP, LLC as of December 31, 2006 included in this prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The combined statements of operations and comprehensive income, changes in parent investment, and cash flows of SAOU and LOU Systems of Targa Resources, Inc. for the period March 12, 2004 (inception) through December 31, 2004 appearing in this Prospectus and Registration Statement, and the combined financial statements of the Midstream Operations sold to Targa Resources, Inc. at April 15, 2004 and for the 106-day period ended April 15, 2004, appearing in this Prospectus and Registration Statement have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their reports thereon appearing elsewhere herein, and are included in reliance upon such report given on the authority of such firm as experts in accounting and auditing.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the Securities and Exchange Commission, or the SEC, a registration statement on Form S-1 regarding our common units. This prospectus does not contain all of the information found in the registration statement. For further information regarding us and our common units offered by this prospectus, you may desire to review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC maintains a web site on the Internet at http://www.sec.gov. Our registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC's web site.

We intend to furnish our unitholders annual reports containing our audited financial statements and furnish or make available quarterly reports containing our unaudited interim financial information for the first three fiscal quarters of each of our fiscal years.

FORWARD-LOOKING STATEMENTS

Some of the information in this prospectus may contain forward-looking statements. These statements can be identified by the use of forward-looking terminology including "may," "believe," "expect," "anticipate," "estimate," "continue," or other similar words. These statements discuss future expectations, contain projections of results of operations or of financial condition, or state other "forward-looking" information. These forward-looking statements involve risks and uncertainties. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this prospectus. The risk factors and other factors noted throughout this prospectus could cause our actual results to differ materially from those contained in any forward-looking statement.

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TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

Introduction

The unaudited pro forma condensed combined financial statements of Targa Resources Partners LP ("the Partnership") as of June 30, 2007, for the years ended December 31, 2006, 2005 and 2004, and for the six months ended June 30, 2007 and 2006 are based upon the historical audited and unaudited financial statements of: (i) Targa Resources Partners LP, (ii) Targa North Texas LP, which owns the North Texas System, and (iii) the SAOU and LOU Systems of Targa Resources, Inc., which owns the SAOU System and the LOU System ("the Acquired Businesses"). Targa Resources Partners LP, Targa North Texas LP and the SAOU and LOU Systems of Targa Resources, Inc. are controlled by a common parent entity, Targa Resources, Inc. The acquisition of the Acquired Businesses by Targa Resources Partners LP in connection with this offering is accounted for and presented under common control accounting. The Acquired Businesses are the accounting Predecessor because they were the first entity controlled by the common parent entity. Under common control accounting, the Acquired Businesses' assets and liabilities are recorded at their book value with the balance of acquisition proceeds recorded as an adjustment to parent equity.

The unaudited pro forma condensed combined balance sheet as of June 30, 2007 has been prepared as if our acquisition of the Acquired Businesses and this offering occurred on June 30, 2007. The unaudited pro forma condensed combined statements of operations for the year ended December 31, 2006 and the six months ended June 30, 2007 have been prepared as if certain transactions effected at the closing of our initial public offering, our acquisition of the Acquired Businesses and this offering had occurred on January 1, 2006. The unaudited pro forma condensed combined statements of operations for the eight and a half months ended December 31, 2004, the year ended December 31, 2005 and the six months ended June 30, 2006 reflect the combined results of operations of Targa North Texas LP and the Acquired Businesses for all periods when such businesses were under the common controlling ownership of Targa Resources, Inc. The unaudited pro forma condensed combined financial statements should be read in conjunction with the notes accompanying these pro forma condensed financial statements and related notes set forth elsewhere in this prospectus.

The adjustments to the historical audited and unaudited financial statements are based upon currently available information and certain estimates and assumptions. Actual effects of these transactions will differ from the pro forma adjustments. However, management believes that the assumptions provide a reasonable basis for presenting the significant effects of the transactions as contemplated and that the pro forma adjustments are factually supportable, give appropriate effect to the expected impact of events that are directly attributable to the transactions, and reflect those items expected to have a continuing impact on the Partnership.

The unaudited pro forma condensed combined financial statements of the Partnership have been derived from the historical financial statements of the Predecessor Businesses and are qualified in their entirety by reference to such historical financial statements and the related notes contained therein. The unaudited pro forma condensed combined financial statements are not necessarily indicative of the results that actually would have occurred if the Partnership has assumed the operations of the Predecessor Businesses on the dates indicated or which would be obtained in the future.

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TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED BALANCE SHEET
June 30, 2007

	Targa Resources Partners LP	Predecessor Business Historical SAOU and LOU Systems of Targa Resources, Inc.	Combined	Transaction Adjustments	Partnership Pro Forma
			(In millions of dollars)		
Current assets:					
Cash	$ 9.4	$ —	$ 9.4	$ —	$ 9.4
				362.7(a)	
				(14.5)(b)	
				(2.0)(c)	
				378.9(d)	
				(3.3)(e)	
				(721.8)(f)	
Trade receivables	1.2	56.0	57.2	—	57.2
Receivables from affiliated companies	50.7	—	50.7	—	50.7
Inventory	—	1.2	1.2	—	1.2
Assets from risk management activities	7.6	3.9	11.5	—	11.5
Other current assets	0.5	—	0.5	—	0.5
	69.4	61.1	130.5	—	130.5
Property, plant and equipment, net	1,046.1	230.2	1,276.3	—	1,276.3
Debt issue costs allocated from Parent	—	3.0	3.0	(3.0)(f)	—
Debt issue costs	3.8	—	3.8	3.3(e)	7.1
Long-term assets from risk management activities	4.5	0.3	4.8	—	4.8
Other long-term assets	—	2.3	2.3	—	2.3
Total assets	$ 1,123.8	$ 296.9	$1,420.7	$ 0.3	$ 1,421.0
LIABILITIES AND PARENT INVESTMENT					
Current liabilities:					
Accounts payable	$ 4.3	$ 2.2	$ 6.5	$ —	$ 6.5
Accrued liabilities	33.9	87.9	121.8	—	121.8
Current maturities of debt allocated from Parent	—	1.1	1.1	(1.1)(f)	—
Liabilities from risk management activities	6.9	10.6	17.5		17.5
Other current liabilities	—	—	—	—	—
Total current liabilities	45.1	101.8	146.9	(1.1)	145.8
Long-term debt allocated from Parent	—	123.2	123.2	(123.2)(f)	—
Long-term debt	294.5	—	294.5	378.9(d)	673.4
Long-term liabilities from risk management activities	11.6	12.5	24.1	—	24.1
Other long-term liabilities	1.7	1.3	3.0	—	3.0
Deferred income tax liability	3.2	0.4	3.6	—	3.6
Total long-term liabilities	311.0	137.4	448.4	255.7	704.1
Commitments and contingencies					
Partners' capital excluding accumulated other comprehensive income	—	57.6	57.6	(57.6)(f)	—
Common unitholders	378.2	—	378.2	362.7(a)	724.4
				(14.5)(b)	
				(2.0)(c)	
Subordinated unitholders	376.7	—	376.7	(510.2)(f)	(133.5)
General partner interest	20.6	—	20.6	7.4(f)	(12.1)
				(40.1)(f)	
Accumulated other comprehensive income	(7.8)	0.1	(7.7)	—	(7.7)
Total liabilities and partners' capital	$ 1,123.8	$ 296.9	$1,420.7	$ 0.3	$ 1,421.0

See accompanying notes to unaudited pro forma condensed combined financial statements

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS
Year ended December 31, 2006

	Targa North Texas LP	Predecessor Business Historical SAOU and LOU Systems of Targa Resources, Inc.	Combined	Transaction Adjustments	Partnership Pro Forma
	(In millions of dollars, except units and per unit data)				
Operating revenues	$ 384.8	$ 1,370.5	$1,755.3	$ —	$ 1,755.3
Costs and expenses:					
Product purchases	269.3	1,248.3	1,517.6	—	1,517.6
Operating expenses	24.1	25.0	49.1	—	49.1
Depreciation and amortization expense	56.0	14.0	70.0	—	70.0
General and administration expense	6.9	9.2	16.1	—	16.1
Total costs and expenses	356.3	1,296.5	1,652.8	—	1,652.8
Income from operations	28.5	74.0	102.5	—	102.5
Other expense:					
Interest expense allocated from parent	(72.9)	(15.1)	(88.0)	88.0(g)	—
Other interest expense	—	—	—	(47.1)(g)	(48.6)
				(1.5)(h)	
Provision for income taxes	(2.5)	(0.4)	(2.9)		(2.9)
Net income (loss)	$ (46.9)	$ 58.5	$ 11.6	$ 39.4	$ 51.0
General partner’s interest in net income					$ 1.0
Limited partners’ interest in net income					$ 50.0
Net income per limited partner unit					$ 1.13
Weighted average number of limited partner units outstanding					44,364,231

See accompanying notes to unaudited pro forma condensed combined financial statements

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS
Year ended December 31, 2005

	Targa North Texas LP Two Months Ended December 31, 2005	Predecessor Business Historical SAOU and LOU Systems of Targa Resources, Inc. Year Ended December 31, 2005	Pro Forma Combined
	(In millions of dollars)		
Operating revenues	$ 75.1	$ 1,085.3	$ 1,160.4
Costs and expenses:			
Product purchases	54.9	1,006.7	1,061.6
Operating expenses	3.5	20.9	24.4
Depreciation and amortization expense	9.2	13.9	23.1
General and administration expense	1.1	15.7	16.8
Total costs and expenses	68.7	1,057.2	1,125.9
Income from operations	6.4	28.1	34.5
Other expense:			
Loss on debt extinguishment allocated from parent	(11.5)	(3.7)	(15.2)
Interest expense allocated from parent	—	(9.6)	(9.6)
Net income (loss)	$ (5.1)	$ 14.8	$ 9.7

See accompanying notes to unaudited pro forma condensed combined financial statements

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS
Year ended December 31, 2004

	Predecessor Business Historical — SAOU and LOU Systems of Targa Resources, Inc. — Eight and a Half Months Ended December 31, 2004
Operating revenues	$ 603.9
Costs and expenses:	
Product purchases	544.9
Operating expenses	15.3
Depreciation and amortization expense	10.4
General and administration expense	11.1
Taxes other than income taxes	—
Loss (gain) on sale of assets	—
Total costs and expenses	581.7
Income from operations	22.2
Other expense:	
Interest expense allocated from parent	(6.1)
Provision for income taxes	—
Net income	$ 16.1

See accompanying notes to unaudited pro forma condensed combined financial statements

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS
Six months ended June 30, 2007

	Targa Resources Partners, LP	Predecessor Business Historical SAOU and LOU Systems of Targa Resources, Inc.	Combined	Transaction Adjustments	Partnership Pro Forma
	(In millions of dollars, except units and per unit data)				
Operating revenues	$ 200.0	$ 561.4	$ 761.4	$ —	$ 761.4
Costs and expenses:					
Product purchases	138.3	527.9	666.2	—	666.2
Operating expenses	12.0	11.9	23.9	—	23.9
Depreciation and amortization expense	28.5	7.2	35.7	—	35.7
General and administration expense	3.5	4.5	8.0	—	8.0
Loss (gain) on sale of assets	—	(0.3)	(0.3)	—	(0.3)
Total costs and expenses	182.3	551.2	733.5	—	733.5
Income from operations	17.7	10.2	27.9	—	27.9
Other expense:					
Interest expense allocated from parent	—	(5.0)	(5.0)	5.0(g)	—
Other Interest expense	(17.7)	0.1	(17.6)	(6.0)(g)	(24.3)
				(0.7)(h)	
Deferred income tax expense	(0.7)	(0.0)	(0.7)	—	(0.7)
Net income (loss)	$ (0.7)	$ 5.3	$ 4.6	$ (1.7)	$ 2.9
General partner's interest in net income					$ 0.1
Limited partner's interest in net income					$ 2.8
Net income per limited partner unit					$ 0.06
Weighted average number of limited partner units outstanding					44,364,231

See accompanying notes to unaudited pro forma condensed combined financial statements

TARGA RESOURCES PARTNERS LP

UNAUDITED PRO FORMA CONDENSED COMBINED STATEMENT OF OPERATIONS
Six months ended June 30, 2006

	Targa North Texas LP	Predecessor Business Historical SAOU and LOU Systems of Targa Resources, Inc.	Combined
	(In millions of dollars)		
Operating revenues	$ 188.9	$ 797.1	$ 986.0
Costs and expenses:			
Product purchases	132.8	733.7	866.5
Operating expenses	11.5	12.3	23.8
Depreciation and amortization expense	27.4	6.7	34.1
General and administration expense	3.2	2.1	5.3
Total costs and expenses	174.9	754.8	929.7
Income from operations	14.0	42.3	56.3
Other expense:			
Interest expense allocated from parent	(35.7)	(7.4)	(43.1)
Deferred income tax expense	(1.5)	(0.4)	(1.9)
Net income (loss)	$ (23.2)	$ 34.5	$ 11.3

See accompanying notes to unaudited pro forma condensed combined financial statements

TARGA RESOURCES PARTNERS LP

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS

1. Basis of Presentation, the Offering and Formation Transactions

The historical financial information is derived from the historical combined financial statements of the Predecessor Businesses. The unaudited pro forma condensed financial information has been prepared by applying pro forma adjustments to the historical audited and unaudited financial statements of Targa Resources Partners LP. The pro forma adjustments have been prepared as if the transactions to be effected at the closing of this offering had taken place on June 30, 2007 in the case of the pro forma balance sheet, or as of January 1, 2006 in the case of the pro forma income statements for the year ended December 31, 2006 and for the six months ended June 30, 2007. The 2004 and 2005 pro forma results of operations and the six months ended June 30, 2006 pro forma results of operations are presented as combined in order to reflect the presentation for entities under common control, for the periods in which these entities were indirect wholly-owned subsidiaries of Targa Resources, Inc. ("Targa").

The pro forma financial statements reflect the following transactions:

- our initial public offering of 19,320,000 common units and related formation transactions in February 2007;
- our purchase of the SAOU and LOU Systems from Targa for $705 million;
- our payment to Targa of $24.2 million for certain hedge transactions associated with the Acquired Businesses effected on September 25 and 26, 2007;
- the issuance of 13,500,000 common units to the public in this offering, representing a 29.8% limited partner interest in us, and the use of the net proceeds therefrom to fund a portion of the purchase price of the SAOU and LOU Systems and to pay expenses associated with this offering;
- the issuance to our general partner of 275,511 general partner units as partial consideration for the SAOU and LOU Systems, enabling it to maintain its 2% general partner interest in us;
- the borrowing of approximately $378.9 million under our amended credit facility and the use of such borrowings to fund a portion of the purchase price of the SAOU and LOU Systems and to pay expenses associated with the amendment of the credit facility.

2. Pro Forma Adjustments and Assumptions

(a) Reflects the gross proceeds to us of $362.7 million from the issuance and sale of 13,500,000 common units at $26.87 per unit.

(b) Reflects the payment of estimated underwriting discounts of $14.5 million, which will be allocated to the common unitholders.

(c) Reflects payment of $2.0 million in estimated expenses associated with this offering and the other Formation Transactions, which will be allocated to the common unitholders.

(d) Reflects approximately $378.9 million in incremental borrowings by us under our revised credit facility.

(e) Reflects estimated fees and expenses of approximately $3.3 million associated with our revised credit facility.

TARGA RESOURCES PARTNERS LP

NOTES TO UNAUDITED PRO FORMA CONDENSED COMBINED FINANCIAL STATEMENTS — (Continued)

(f) Reflects the payments to Targa of the net proceeds from the offering and borrowings under our revised credit facility as partial consideration for the Acquired Businesses as follows (in millions):

Gross proceeds from sale of common units	$362.7
Borrowings under our revised credit facility	378.9
Discounts, fees and other offering expenses	(16.5)
Estimated fees and expenses of revised credit facility	(3.3)
	$721.8

The pro forma elimination/transaction adjustments associated with this issuance are:

Elimination of SAOU and LOU allocated debt from Parent	$124.3
Elimination of SAOU and LOU capital accounts	57.6
Elimination of SAOU and LOU allocated debt issue costs	(3.0)
Issuance of 275,511 general partner units as partial consideration for the Acquired Businesses	(7.4)
Adjustments for purchase of assets under common control:	
Subordinated unitholders	510.2
General partner	40.1
	$721.8

(g) Reflects the reversal of interest expense associated with allocated debt and interest expense under the revised credit facility discussed in (d) as though the borrowing occurred effective January 1, 2006 and 2007, respectively. Interest is calculated assuming a pro forma debt balance of $673.4 million, of which $378.9 million is attributable to debt incurred in connection with our acquisition of the Acquired Businesses and $294.5 million is attributable to debt incurred in connection with our initial public offering at an estimated annual interest rate of 7%. A one-eighth percentage point change in the interest rate would change pro forma interest expense by $0.8 million for the year ended December 31, 2006 and $0.4 million for the six month period ended June 30, 2007.

(h) Reflects amortization of the debt issue costs associated with our existing and revised five year credit facility.

Report of Independent Registered Public Accounting Firm

To the Partners of Targa North Texas LP:

In our opinion, the accompanying combined balance sheets and the related combined statements of operations and comprehensive income (loss), of changes in partners' capital/net parent equity, and of cash flows present fairly, in all material respects, the financial position of Targa North Texas LP (the "Partnership") at December 31, 2006 and 2005 and the results of its operations and its cash flows for the year ended December 31, 2006, and the two months ended December 31, 2005 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 audit. 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 audit provides a reasonable basis for our opinion.

As discussed in Note 9 to the 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 30, 2007

Report of Independent Registered Public Accounting Firm

To the Partners of Targa North Texas LP:

In our opinion, the accompanying combined statements of operations and comprehensive income (loss), of changes in partners' capital/net parent equity, and of cash flows present fairly, in all material respects, the results of operations of the North Texas System ("TNT LP Predecessor") and its cash flows for the ten months ended October 31, 2005, and the year ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of 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 audits 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 9 to the financial statements, the North Texas System has engaged in significant transactions with other subsidiaries of its parent company, Dynegy Inc., a related party.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
November 13, 2006

TARGA NORTH TEXAS LP

COMBINED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In thousands)	
ASSETS (Collateral for Parent debt — See Note 6)		
Current assets:		
Trade receivables, net of allowances of $0 and $15	$ 1,310	$ 1,525
Inventory	—	1,155
Assets from risk management activities	17,250	34
Deposits	—	630
Total current assets	18,560	3,344
Property, plant, and equipment, at cost	1,129,210	1,106,107
Accumulated depreciation	(65,102)	(9,126)
Property, plant, and equipment, net	1,064,108	1,096,981
Debt issue costs allocated from Parent	17,612	22,494
Long-term assets from risk management activities	15,541	24
Total assets (collateral for Parent debt — See Note 6)	$1,115,821	$1,122,843
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 2,789	$ 2,145
Accrued liabilities	28,832	30,595
Current maturities of debt allocated from Parent	281,083	4,932
Liabilities from risk management activities	—	53
Total current liabilities	312,704	37,725
Long-term debt allocated from Parent	582,877	863,960
Long-term liabilities from risk management activities	96	72
Other long-term liabilities	1,684	1,541
Deferred income tax liability	2,844	—
Commitments and contingencies (see Note 8)		
Partners' capital:		
General partner	107,808	109,772
Limited partner	107,808	109,773
Total partners' capital	215,616	219,545
Total liabilities and partners' capital	$1,115,821	$1,122,843

See notes to combined financial statements

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TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	TNT LP		TNT LP Predecessor	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(In thousands)			
Revenues from third parties	$ 15,224	$ 22,192	$ 8,732	$ 12,039
Revenues from affiliates	369,605	52,952	284,603	246,516
Total operating revenues	384,829	75,144	293,335	258,555
Costs and expenses:				
Product purchases from third parties	268,487	54,981	209,835	182,234
Product purchases from affiliates	846	11	1,024	278
Operating expense, excluding DD&A	24,102	3,494	18,035	17,702
Depreciation and amortization expense	55,958	9,150	11,262	12,201
General and administrative expense	6,904	1,063	7,273	7,230
Loss (gain) on sale of assets	—	—	(32)	329
	356,297	68,699	247,397	219,974
Income from operations	28,532	6,445	45,938	38,581
Other expense:				
Interest expense allocated from Parent	(72,910)	(11,542)	—	—
Income (loss) before income taxes	(44,378)	(5,097)	45,938	38,581
Deferred income tax benefit	(2,532)	—	—	—
Net income (loss)	(46,910)	(5,097)	45,938	38,581
Other comprehensive income (loss):				
Change in fair value of commodity hedges	35,189	—	—	—
Reclassification adjustment for settled periods	(4,610)	—	—	—
Related income taxes	(312)	—		
Change in fair value of interest rate swaps	1,047	(99)	—	—
Reclassification adjustment for settled periods	(404)	32	—	—
Other comprehensive income (loss)	30,910	(67)	—	—
Comprehensive income (loss)	$ (16,000)	$ (5,164)	$ 45,938	$ 38,581

See notes to combined financial statements

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TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL/NET PARENT EQUITY

	Targa North Texas LP		Targa North Texas LP Predecessor Equity	Total
	General Partner	Limited Partner		
	(In thousands)			
Balance, December 31, 2003	$ —	$ —	$ 164,802	$164,802
Distributions	—	—	(34,573)	(34,573)
Net income	—	—	38,581	38,581
Balance, December 31, 2004	—	—	168,810	168,810
Distributions	—	—	(56,268)	(56,268)
Net income	—	—	45,938	45,938
Balance, October 31, 2005	—	—	158,480	158,480
Initial contribution	109,939	109,940	—	219,879
Other contributions	2,415	2,415	—	4,830
Other comprehensive loss	(34)	(33)	—	(67)
Net loss	(2,548)	(2,549)	—	(5,097)
Balance, December 31, 2005	109,772	109,773	—	219,545
Other contributions	6,036	6,035		12,071
Other comprehensive income	15,455	15,455	—	30,910
Net loss	(23,455)	(23,455)	—	(46,910)
Balance, December 31, 2006	$107,808	$107,808	$ —	$215,616

See notes combined financial statements

TARGA NORTH TEXAS LP

COMBINED STATEMENTS OF CASH FLOWS

	TNT LP		TNT LP Predecessor	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(In thousands)			
Cash flows from operating activities				
Net income (loss)	$ (46,910)	$ (5,097)	$ 45,938	$ 38,581
Adjustments to reconcile net income (loss) to cash flows provided by (used in) operating activities:				
Depreciation	55,958	9,150	11,262	12,201
Accretion	144	35	187	204
Amortization of debt issue costs and debt payments allocated from Parent	5,154	848	—	—
Loss (gain) on sale of assets	—	—	(32)	329
Deferred taxes	2,532	—	—	—
Hedge premium	(1,541)	—	—	—
Changes in operating assets and liabilities:				
Accounts receivable	215	(60)	(280)	683
Inventory	1,155	(1,155)	423	87
Other assets	630	10	51	(574)
Accounts payable	644	(845)	(1,334)	2,658
Accrued liabilities	(1,763)	(4,357)	16,490	3,850
Net cash provided by (used in) operating activities	16,218	(1,471)	72,705	58,019
Cash flows from investing activities				
Purchases of property, plant, and equipment	(23,117)	(2,134)	(16,469)	(23,664)
Proceeds from asset sales	32	8	32	218
Net cash used in investing activities	(23,085)	(2,126)	(16,437)	(23,446)
Cash flows from financing activities				
Contributions (distributions)	6,867	3,597	(56,268)	(34,573)
Net cash provided by (used in) financing activities	6,867	3,597	(56,268)	(34,573)
Net increase in cash and cash equivalents	—	—	—	—
Cash and cash equivalents, beginning of period	—	—	—	—
Cash and cash equivalents, end of period	$ —	$ —	$ —	$ —
Supplemental cash flow information:				
Noncash investing and financing activities:				
Property, plant and equipment allocated from Parent	$ —	$ 907,634	$ —	$ —
Debt issue costs allocated from Parent	272	23,342	—	—
Long-term debt allocated from Parent	4,932	870,125	—	—

See notes to combined financial statements

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS

Note 1 — Organization and Operations

Targa North Texas LP ("TNT LP") is a Delaware limited partnership formed on November 28, 2005 to control, manage and operate Targa Resources, Inc.'s ("Targa Resources") North Texas System. TNT LP is owned 50% by its general partner, Targa North Texas GP LLC, a Delaware limited liability company, and 50% by its sole limited partner, Targa LP Inc., a Delaware corporation. The partnership agreement requires all items of income and expense, and all distributions to be allocated among the partners in accordance with their ownership ratios. The general partner and limited partner are indirect wholly-owned subsidiaries of Targa Resources.

Targa Resources acquired the North Texas System on October 31, 2005 as part of its acquisition of substantially all of Dynegy Inc. ("Dynegy")'s midstream natural gas business (the "DMS acquisition"). On December 1, 2005, in a series of transactions, Targa Resources conveyed the North Texas System to TNT LP.

Prior to October 31, 2005, the North Texas System was owned by an indirect wholly-owned subsidiary of Dynegy, and is presented in these financial statements as "TNT LP Predecessor".

The North Texas System consists of two wholly-owned natural gas processing plants and an extensive network of integrated gathering pipelines that serve a 14 county natural gas producing region in the Fort Worth Basin in North Central Texas. The natural gas processing facilities comprised the Chico processing and fractionation facilities and the Shackelford processing facility.

On February 14, 2007, TNT LP was contributed to Targa Resources Partners LP, or TRP LP, in conjunction with an underwritten initial public offering (or IPO) of TRP LP's common units. See Note 14.

Note 2 — Basis of Presentation

Targa Resources' conveyance of the North Texas System to TNT LP 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."* Therefore, Targa Resources' results of the North Texas System from November 1, 2005 to December 1, 2005 have been combined with TNT LP's results subsequent to December 1, 2005 as TNT LP's combined results for the two months ended December 31, 2005. Additionally, TNT LP's financial position, results of operations and cash flows as of and for the two months ended December 31, 2005 reflect Targa Resources' allocation of the fair value of the North Texas Assets and indebtedness related to the DMS acquisition (See Note 4 and Note 6).

The accompanying financial statements and related notes present TNT LP's financial position as of December 31, 2006 and 2005; TNT LP's results of operations, cash flows and changes in partners' capital for the year ended December 31, 2006, and the two months ended December 31, 2005 and the combined results of operations, cash flows and changes in net equity of parent of TNT LP Predecessor for the ten months ended October 31, 2005 and the year ended December 31, 2004. TNT LP's financial data has been separated from the TNT LP Predecessor financial data by a bold black line.

In the accompanying financial statements and related notes, references to the "Parent" are to Dynegy as of and prior to October 31, 2005, and to Targa Resources subsequent to October 31, 2005.

Throughout the periods covered by the combined financial statements, the Parent has provided cash management services to TNT LP and TNT LP Predecessor through a centralized treasury system. As a result, all of TNT LP and TNT LP Predecessor's 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 the combined statements of partners' capital/net parent equity. As a result of this accounting treatment, TNT LP's working capital does not reflect any affiliate accounts receivable for intercompany commodity sales or any affiliate

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

accounts payable for personnel and services and for intercompany product purchases. Consequently, TNT LP had negative working capital balances of $294.1 million and $34.4 million at December 31, 2006 and 2005. Despite the negative working capital balance, TNT LP generated operating cash flows of $16.2 million for the year ended December 31, 2006, used $1.5 million for the two months ended December 31, 2005, and generated $72.7 million for the ten months ended October 31, 2005. Investing cash flows of $23.1 million for the year ended December 31, 2006 and $2.1 million for the two months ended December 31, 2005 were funded with the operating cash flows and a deemed capital contributions of $6.9 million and $3.6 million, respectively. Cash flows from operations for the ten months ended October 31, 2005 were sufficient to fund investing cash flows of $16.4 million. In addition, distributions to the Parent of $56.3 million for the ten months ended October 31, 2005 were also funded through operating cash flows.

TNT LP and TNT LP Predecessor have been allocated general and administrative expenses incurred by the Parent in order to present financial statements on a stand-alone basis. See Note 9 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 TNT LP and TNT LP Predecessor been operated as stand-alone entities.

Note 3 — Significant Accounting Policies

Asset Retirement Obligations. TNT LP and TNT LP Predecessor account for asset retirement obligations ("AROs") using SFAS 143, *"Accounting for Asset Retirement Obligations," as interpreted by Financial Interpretation, or "FIN", 47, "Accounting for Conditional Asset Retirement Obligations."* Asset retirement obligations are legal obligations associated with the retirement of a tangible long-lived asset 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 combined 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 value 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 incur a gain or loss on the difference between the recorded amount and the actual settlement cost. TNT LP Predecessor adopted SFAS 143 on January 1, 2003. See Note 7 for information regarding TNT LP and TNT LP Predecessor's AROs.

Cash and Cash Equivalents. See centralized cash management in Note 9 — 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.

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

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

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 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. There were no indicators of asset impairments as of December 31, 2006 and 2005.

Income Taxes. TNT LP and TNT LP Predecessor are not subject to federal income taxes. As a result, their earnings or losses for federal income tax purposes have been included in the tax returns of their individual partners or owners. In May 2006, Texas adopted a margin tax consisting of a 1% tax on the amount by which total revenue exceeds cost of goods. Accordingly, we have estimated our liability for this tax.

Natural Gas Imbalances. Quantities of natural gas 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, gas imbalances receivable are valued at the lower of cost or market; gas imbalances payable are valued at replacement cost. These imbalances are typically settled in the following month with deliveries of natural gas. 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.

Price Risk Management (Hedging). TNT LP 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 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.

TNT LP'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, TNT LP will assess whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Hedge effectiveness is measured on a quarterly basis. Any ineffective portion of the unrealized gain or loss is reclassified to earnings in the current period.

TNT LP Predecessor did not engage in hedging activities.

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 TNT LP and TNT LP Predecessor'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. TNT LP and TNT LP Predecessor's primary types of sales and service activities reported as operating revenue include:

- sales of natural gas, NGLs and condensate; and
- natural gas processing, from which we generate revenue through the compression, gathering, treating, and processing of natural gas.

TNT LP and TNT LP Predecessor recognize revenue associated 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, TNT LP and TNT LP Predecessor receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, TNT LP and TNT LP Predecessor are paid for their services by keeping a percentage of the NGLs extracted and the residue gas resulting from processing natural gas. In percent-of-proceeds arrangements, TNT LP and TNT LP Predecessor remit either a percentage of the proceeds received from the sales of residue gas and NGLs or a percentage of the residue gas or NGLs at the tailgate of the plant to the producer. Under the terms of percent-of-proceeds and similar contracts, TNT LP and TNT LP Predecessor may purchase the producer's share of the processed commodities for resale or deliver the commodities to the producer at the tailgate of the plant. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, TNT LP and TNT LP Predecessor keep the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. Natural gas or NGLs that TNT LP and TNT LP Predecessor receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee based contracts, TNT LP and TNT LP Predecessor receive a fee-based on throughput volumes.

TNT LP and TNT LP Predecessor generally report revenues gross in the combined statements of operations, in accordance with Emerging Issues Task Force, or "EITF", Issue 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent." Except for fee-based contracts, TNT LP and TNT LP Predecessor act as the principal in these 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. TNT LP operates in one segment only, the natural gas gathering and processing segment, as did TNT LP Predecessor.

Use of Estimates. TNT LP and TNT LP Predecessor's preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect their reported financial position and results of operations. Management reviews significant estimates and judgments affecting the combined financial statements on a recurring basis and records the effect of any necessary adjustments prior to their publication. 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 December 2004, the FASB released its final revised standard entitled SFAS 123(R), *"Share-Based Payment,"* which will significantly change accounting practice with respect to employee stock options and other stock based compensation. SFAS 123(R) requires companies to recognize, as an operating expense, the estimated fair value of share-based payments to employees, including grants of employee stock options. Because TNT LP does not have any employees, its adoption of SFAS 123(R) on January 1, 2006 will only be affected by the allocation of stock-based compensation cost by the Parent. Such allocation is not expected to have a material effect on TNT LP's financial statements.

In September 2005, the FASB ratified the consensus on EITF 04-13, *"Accounting for Purchases and Sale of Inventory With the Same Counterparty."* EITF 04-13 relates to an entity that may sell inventory to another entity in the same line of business from which it also purchases inventory. This guidance is effective for new (including renegotiated or modified) inventory arrangements entered into in the first interim or annual reporting period beginning after March 15, 2006. TNT LP's adoption of EITF 04-13 on April 1, 2006 had no effect on its financial statements.

In July 2006, the FASB issued FIN 48, *"Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109"*, which clarifies the accounting and disclosure for uncertainty in income taxes recognized in an enterprise's financial statements. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. We continue to evaluate our tax positions, and based on our current evaluation, anticipate FIN 48 will not have a significant impact on our results of operations or financial position.

We adopted SFAS 154, *"Accounting Changes and Error Corrections,"* on January 1, 2006. SFAS 154 provides guidance on the accounting for and reporting of accounting changes and error corrections.

In September 2006, the FASB issued SFAS 157 *"Fair Value Measurements."* SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles ("GAAP"), and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements, the Board having previously concluded in these accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. TNT LP has not yet determined the impact this interpretation will have on its financial statements.

We adopted the guidance in Securities and Exchange Commission ("SEC") Staff Accounting Bulletin 108 ("SAB 108"). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 had no effect on TNT LP's results of operations or financial position.

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. TNT LP is currently reviewing this new accounting standard and the impact, if any, it will have on its financial statements.

Note 4 — Change of Control

On October 31, 2005, Targa Resources completed the DMS acquisition for $2,452 million in cash. Approximately $1,067 million of the total purchase price was allocated to the net assets of the North Texas System. Additionally, $870.1 million of Targa Resources' acquisition-related long-term debt (see Note 6) and $23.3 million in associated debt issue costs were allocated to the North Texas System. The following presents the portion of the purchase price and related long-term debt and debt issue costs allocated to the North Texas System based on the estimated fair values of the assets acquired and liabilities assumed (in thousands):

Current assets	$ 2,105
Property, plant, and equipment	1,104,000
Debt issue costs	23,342
Current liabilities	(37,937)
Long-term debt	(870,125)
Asset retirement obligations	(1,506)
Initial contribution	$ 219,879

The following unaudited pro forma financial information presents the combined results of operations of the North Texas System as if the DMS acquisition had been completed on January 1 of the years presented, after including certain pro forma adjustments for interest expense on long-term debt allocated from the Parent, and depreciation and amortization. The pro forma information is not necessarily indicative of the results of operations had the acquisition occurred on January 1 of the year presented or the results of operations that may be obtained in the future.

	Pro Forma Year Ended December 31, 2005
	(Unaudited) (In thousands)
Revenues	$ 368,479
Product purchases	(265,851)
Depreciation and amortization expense	(54,876)
Gain (loss) on sale of assets	32
Other operating expense	(29,865)
Income (loss) from operations	17,919
Interest expense	(69,252)
Net loss	$ (51,333)

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

Note 5 — Property, Plant, and Equipment

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

	December 31, 2006	December 31, 2005
	(In thousands)	
Gathering and processing systems	$ 1,113,799	$ 1,078,402
Other property and equipment	15,411	27,705
	1,129,210	1,106,107
Accumulated depreciation	(65,102)	(9,126)
	$ 1,064,108	$ 1,096,981

Note 6 — Long-Term Debt

TNT LP's long-term debt, all of which has been allocated from the Parent, consisted of the following at the dates indicated:

	TNT LP December 31, 2006	TNT LP December 31, 2005
	(In thousands)	
Outstanding debt	$ 863,960	$ 868,892
Current maturities of debt	(281,083)	(4,932)
Long-term debt	$ 582,877	$ 863,960

Allocation of Long-Term Debt from the Parent

The Parent debt was allocated to identifiable assets groups which collateralize the debt based on the value of the acquired assets. The collateralization base includes all the Parent's assets and equity interests. The senior unsecured notes were allocated to identifiable tangible asset groups that are guarantors of the notes.

The following table presents the components of the Parent's acquisition-related debt that was allocated to TNT LP, as of December 31, 2006 and 2005.

	December 31, 2006	December 31, 2005
	(In thousands)	
Senior secured term loan facility, variable rate, 6.7% at December 31, 2006, due October 2011	$ 486,962	$ 491,894
Senior secured asset sale bridge loan facility, variable rate, 7.6% at December 31, 2006, due October 2007	276,151	276,151
Senior unsecured notes, 8.5% fixed rate, due November 2013	100,847	100,847
Total principal amount	863,960	868,892
Less current maturities of debt	(281,083)	(4,932)
Long-term debt	$ 582,877	$ 863,960

The following table presents information regarding variable interest rates paid on the Parent debt for the year ended December 31, 2006.

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Senior secured term loan facility	6.59% to 7.75%	7.03%
Senior secured asset sale bridge loan facility	6.83% to 7.62%	7.26%

Interest expense on long-term debt allocated to TNT LP is settled through an adjustment to partners' capital (see Note 9 — Related Party Transactions).

Debt Maturity Table

The following table presents the scheduled maturities of principal amounts of the Parent's long-term debt allocated to TNT LP as of December 31, 2006 (in thousands).

	Allocated to TNT LP
2007	$ 281,083
2008	4,932
2009	4,932
2010	4,932
2011	4,932
Thereafter	563,149
	$ 863,960

Critical Terms of Parent Debt Obligations

Senior Secured Credit Facility

On October 31, 2005, the Parent entered into a $2,500 million senior secured credit agreement with a syndicate of financial institutions and other institutional lenders. The credit agreement includes a $300 million senior secured letter of credit facility.

Borrowings under the senior secured credit agreement, other than the senior secured synthetic letter of credit facility, bear interest at a rate equal to an applicable margin plus, at the Parent's option, either (a) a base rate determined by reference to the higher of (1) the prime rate of Credit Suisse and (2) the federal funds rate plus $^1/_2$ of 1% or (b) LIBOR as determined by reference to the costs of funds for dollar deposits for the interest period relevant to such borrowing adjusted for certain statutory reserves. The initial applicable margin for borrowings under the senior secured revolving credit facility is 1.25% with respect to base rate borrowings and 2.25% with respect to LIBOR borrowings. Upon repayment of the senior secured asset sale bridge loan facility, the margin for borrowings under the senior secured revolving credit facility will be 1.00% with respect to base rate borrowings and 2.00% with respect to LIBOR borrowings. The applicable margin for borrowings under the senior secured revolving credit facility may fluctuate based upon the Parent's leverage ratio as defined in the credit agreement.

The Parent is required to pay a facility fee, quarterly in arrears, to the lenders under the senior secured synthetic letter of credit facility equal to (i) 2.25% of the amount on deposit in the designated deposit account plus (ii) the administrative cost incurred by the deposit account agent for such quarterly period.

In addition to paying interest on outstanding principal under the senior secured credit facilities, the Parent is required to pay a commitment fee equal to 0.50% of the currently unutilized commitments thereunder. The commitment fee rate may fluctuate based upon the Parent's leverage ratios.

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

All obligations under the Parent's senior secured credit agreement and certain secured hedging arrangements are unconditionally guaranteed, subject to certain exceptions, by each of its existing and future domestic restricted subsidiaries, including TNT LP.

All obligations under the senior secured credit facilities and certain secured hedging arrangements, and the guarantees of those obligations, are secured by substantially all of the following assets, subject to certain exceptions:

- a pledge of TNT LP's general partner and limited partner interests; and
- a security interest in, and mortgages on, TNT LP's tangible and intangible assets.

8$^1/_2$% Senior Notes due 2013

On October 31, 2005 the Parent completed the private placement of $250 million in aggregate principal amount of senior unsecured notes ("the Notes").

Interest on the Notes accrues at the rate of 8$^1/_2$% per annum and is payable in arrears on May 1 and November 1. Interest is computed on the basis of a 360-day year comprising twelve 30-day months. Additional interest may accrue on the Notes in certain circumstances pursuant to a registration rights agreement.

The Notes are the Parent's unsecured senior obligations, and are guaranteed by TNT LP, subordinate to its guarantee of the Parent's borrowings under its senior secured credit facility.

Interest Rate Swaps

In connection with its Senior Secured Credit Facility, the Parent entered into interest rate swaps with a notional amount of $350 million. The interest rate swaps effectively fix the interest rate on $350 million in borrowings under the Senior Secured Credit Facility to a rate of 4.8% plus the applicable LIBOR margin (2.25% at December 31, 2006) through November 2007.

The change in fair value of the interest rate swaps, together with the related accumulated other comprehensive income and interest expense has been allocated to TNT LP in the same proportion as the allocation of the Parent's borrowings under its Senior Secured Credit Facility.

Note 7 — Asset Retirement Obligations

The following table reflects the changes in TNT LP and TNT LP Predecessor's AROs during the periods shown.

	TNT LP		TNT LP Predecessor	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(In thousands)			
Beginning of period	$ 1,541	$ 2,054	$ 1,897	$ 1,838
Liabilities incurred	—	—	—	—
Change in estimate	(1)	(548)	(30)	(145)
Accretion expense	144	35	187	204
End of period	$ 1,684	$ 1,541	$ 2,054	$ 1,897

In connection with the purchase price allocation for the DMS Acquisition, management revised the estimated remaining lives of TNT LP's long-lived assets, which together with the revised discount rate as of the acquisition date, resulted in a $0.5 million downward revision in its AROs as of October 31, 2005.

Note 8 — Commitments and Contingencies

Contractual obligations pertain to a natural gas pipeline capacity agreement on certain interstate pipelines entered into during 2005, operating leases and AROs. Future non-cancelable commitments related to these obligations are presented below (in millions).

	2007	2008	2009	2010	2011+
Capacity payments	$2.6	$2.5	$2.4	$0.8	$ —
Operating leases	0.1	0.1	0.1	—	—
AROs	—	—	—	—	1.7
	$2.7	$2.6	$2.5	$0.8	$ 1.7

Total expenses related to capacity payments were $2.6 million, $0.1 million, and $0.4 million for the year ended December 31, 2006, the two months ended December 31, 2005, and the ten months ended October 31, 2005, respectively. There were no capacity payments made for the year ended December 31, 2004.

Environmental

For environmental matters, TNT LP and TNT LP Predecessor record liabilities when remedial efforts are probable and the costs can be 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.

TNT LP's environmental liability was $0.3 million and $0.1 million, at December 31, 2006 and 2005, respectively, primarily for ground water assessment and remediation.

Litigation Summary

TNT LP is not a party to any legal proceeding other than legal proceedings arising in the ordinary course of its business. TNT LP is a party to various administrative and regulatory proceedings that have arisen in the ordinary course of its business.

Note 9 — Related Party Transactions

Sales to and purchases from affiliates. TNT LP and TNT LP Predecessor routinely conduct business with other subsidiaries of the Parent. The related transactions result primarily from purchases and sales of natural gas and natural gas liquids. In addition, all of TNT LP and TNT LP Predecessor's expenditures are paid through the Parent, resulting in inter-company transactions. Unlike sales transactions with third parties that settle in cash, settlement of these sales transactions occurs through adjustment to partners' capital/net parent equity.

Allocation of costs. The employees supporting TNT LP and TNT LP Predecessor's operations are employees of the Parent. TNT LP and TNT LP Predecessor's financial statements include costs allocated to them by the Parent for centralized general and administrative services performed by the Parent, as well as depreciation of assets utilized by the Parent's centralized general and administrative functions. Costs were allocated to TNT LP Predecessor based on its proportionate share of the Parent's assets, revenues and employees. Costs allocated to TNT LP were based on identification of the Parent's resources which directly benefit TNT LP and its proportionate share of costs based on TNT LP'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 TNT LP and TNT LP Predecessor had been operated as stand-alone entities. These allocations are not settled in cash. Settlement of these allocations occurs through adjustment to partners' capital/net parent equity.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. TNT LP's financial statements include long-term debt, debt issue costs, interest rate swaps and interest expense allocated from the Parent. The allocations were calculated in a manner similar to the acquisition purchase price allocation, and based on the fair value of acquired tangible assets plus related net working capital and unconsolidated equity interests. These allocations are not settled in cash. Settlement of these allocations occurs through adjustment to partners' capital.

The following table summarizes the sales to and purchases from affiliates of the Parent, payments made or received by the Parent on behalf of TNT LP and TNT LP Predecessor, and allocations of costs from the Parent which are settled through adjustment to partners' capital/net parent equity. Management believes these transactions are executed on terms that are fair and reasonable.

	TNT LP		TNT LP Predecessor	
	Year Ended December 31, 2006	Two Months Ended December 31, 2005	Ten Months Ended October 31, 2005	Year Ended December 31, 2004
	(In thousands)			
Cash				
Sales to affiliates	$ (369,605)	$ (52,952)	$ (284,603)	$ (246,516)
Purchases from affiliates	846	11	1,024	278
Payments made by the Parent	300,967	44,781	220,038	204,435
Parent allocation of interest expense	67,756	10,694	—	—
Parent allocation of general and administrative expense	6,903	1,063	7,273	7,230
	6,867	3,597	(56,268)	(34,573)
Noncash				
Initial contribution by Parent (see Note 4)	—	219,879	—	—
Other	272	—	—	—
Parent allocation of debt repayments	4,932	1,233	—	—
	5,204	221,112	—	—
Transactions settled through adjustments to partners' capital/net parent equity	$ 12,071	$ 224,709	$ (56,268)	$ (34,573)

Centralized cash management. The Parent operates a cash management system whereby excess cash from most of their various subsidiaries, held in separate bank accounts, is swept to a centralized account. Cash distributions are deemed to have occurred through partners' capital/net parent equity, and are reflected as an adjustment to partners' capital/net parent equity. Deemed net contributions of cash by TNT LP's parent were $6.9 million for the year ended December 31, 2006 and $3.6 million for the two months ended December 31, 2005. Net cash distributions to TNT LP Predecessor's parent were $56.3 million, and $34.6 million for the ten months ended October 31, 2005, and the year ended December 31, 2004, respectively.

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 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, 2006:

Period	Commodity	Instrument Type	Daily Volumes	Average Price	Index
Jan 2007 — Dec 2007	Natural gas	Swap	4,200 MMBtu	$9.14 per MMBtu	IF-Waha
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 2007 — Dec 2007	Condensate	Swap	319 barrels	75.27 per barrel	NY-WTI
Jan 2008 — Dec 2008	Condensate	Swap	264 barrels	72.66 per barrel	NY-WTI
Jan 2009 — Dec 2009	Condensate	Swap	202 barrels	70.60 per barrel	NY-WTI
Jan 2010 — Dec 2010	Condensate	Swap	181 barrels	69.28 per barrel	NY-WTI

Note 10 — Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

TNT LP operates in the midstream energy industry. Its business activities include gathering, transporting and processing of natural gas, NGL 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, NGL, 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.

TNT LP's profitability could be impacted by a decline in the volume of natural gas, NGL 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, NGL and crude oil handled by TNT LP's 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 TNT LP's results of operations, cash flows and financial position.

Counterparty Risk with Respect to Financial Instruments

Where TNT LP is 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 TNT LP's counterparties.

Casualties or Other Risks

The Parent maintains coverage in various insurance programs on TNT LP's behalf, which provides it with property damage, business interruption and other coverages which are customary for the nature and scope of its operations.

Management believes that the Parent 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, the Parent may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If TNT LP were to incur a significant liability for which it was not fully insured, it could have a material impact on its combined 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 TNT LP's combined operations, or which causes TNT LP to make significant expenditures not covered by insurance, could reduce its ability to meet its financial obligations.

Note 11 — Derivative Instruments and Hedging Activities

At December 31, 2006, OCI consisted of $30.8 million ($30.5 million, net of tax) of unrealized net gains on commodity hedges, and $0.6 million ($0.6 million, net of tax) of unrealized net gains on interest rate hedges allocated from the Parent.

At December 31, 2005, OCI consisted of $0.1 million ($0.1 million, net of tax) of unrealized losses on interest rate hedges allocated from the Parent.

During 2006, deferred net gains on commodity hedges of $4.6 million were reclassified from OCI and credited to income as an increase in revenues, and deferred net gains on interest rate hedges of $0.4 million were reclassified from OCI and credited to income as a reduction in interest expense. There were no adjustments for hedge ineffectiveness.

During 2005, deferred net losses on interest rate hedges of $32,000 were reclassified from OCI and charged to expense as commodity settlements. There were no adjustments for hedge ineffectiveness.

At December 31, 2006, $16.7 million ($16.4 million, net of tax) of deferred net gains on commodity hedges and $0.6 million ($0.6 million, net of tax) of deferred net gains on interest rate hedges recorded in OCI are expected to be reclassified to earnings during the next twelve months.

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

At December 31, 2006, TNT LP had the following hedging arrangements:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	IF-NGPL MC	8.56	8,152	—	—	—	$ 7,262
Swap	IF-NGPL MC	8.43	—	6,964	—	—	3,444
Swap	IF-NGPL MC	8.02	—	—	6,256	—	1,677
Swap	IF-NGPL MC	7.43	—	—	—	5,685	932
			8,152	6,964	6,256	5,685	13,315
Swap	IF-Waha	8.73	5,460	—	—	—	4,606
Swap	IF-Waha	8.53	—	4,657	—	—	1,787
Swap	IF-Waha	7.96	—	—	4,196	—	809
Swap	IF-Waha	7.38	—	—	—	3,809	514
			5,460	4,657	4,196	3,809	7,716
Total Swaps			13,612	11,621	10,452	9,494	21,031
Floor	IF-NGPL MC	6.45	520	—	—	—	200
Floor	IF-NGPL MC	6.55	—	1,000	—	—	342
Floor	IF-NGPL MC	6.55	—	—	850	—	246
			520	1,000	850	—	788
Floor	IF-Waha	6.70	350	—	—	—	137
Floor	IF-Waha	6.85	—	670	—	—	231
Floor	IF-Waha	6.55	—	—	565	—	154
			350	670	565	—	522
Total Floors			870	1,670	1,415	—	1,310
							$ 22,341

NGL

Instrument Type	Index	Avg. Price $/gal	Barrels per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	OPIS-MB	$0.99	2,416	—	—	—	$ 3,553
Swap	OPIS-MB	0.95	—	2,160	—	—	2,235
Swap	OPIS-MB	0.91	—	—	1,948	—	1,223
Swap	OPIS-MB	0.88	—	—	—	1,759	606
			2,416	2,160	1,948	1,759	$ 7,617

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per Day 2007	2008	2009	2010	Fair Value (In thousands)
Swap	NY-WTI	$72.82	439	—	—	—	$ 1,225
Swap	NY-WTI	70.68	—	384	—	—	415
Swap	NY-WTI	69.00	—	—	322	—	183
Swap	NY-WTI	68.10	—	—	—	301	152
Total Swaps			439	384	322	301	1,975
Floor	NY-WTI	$58.60	25	—	—	—	19
Floor	NY-WTI	60.50	—	55	—	—	83
Floor	NY-WTI	60.00	—	—	50	—	84
Total Floors			25	55	50	—	186
			464	439	372	301	$ 2,161

These contracts may expose TNT LP to the risk of financial loss in certain circumstances. These hedging arrangements provide TNT LP with protection on the hedged volumes if prices decline below the prices at which these hedges were set but, if prices increased, the fixed price nature of the swap-related hedges will cause TNT LP to receive less revenue on the hedged volumes than it would receive in the absence of hedges.

The following table shows the balance sheet classification of the fair value of TNT LP's open commodity derivatives and allocated interest rate swaps at December 31, 2006.

	December 31, 2006	2005
	(In thousands)	
Current assets	$17,250	$ 34
Noncurrent assets	15,541	24
Current liabilities	—	(53)
Noncurrent liabilities	(96)	(72)
	$32,695	$(67)

Note 12 — Income Taxes

On May 18, 2006, the Governor of Texas signed into law House Bill 3 ("HB-3") which modifies the existing Texas franchise tax law. The modified franchise tax will be computed by subtracting either costs of goods sold or compensation expense, as defined in HB-3, from gross revenue to arrive at a gross margin. The resulting gross margin will be taxed at a one percent tax rate. HB-3 has also expanded the definition of tax paying entities to include limited partnerships thereby now subjecting TNT LP to a new state tax expense. HB-3 becomes effective for activities occurring on or after January 1, 2007. TNT LP believes that this tax should still be accounted for as an income tax, following the provisions of SFAS 109, because it has the characteristics of an income tax. During 2006, TNT LP recorded a charge to deferred income tax expense of $2.5 million and $0.3 million to OCI.

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

Note 13 — Selected Quarterly Financial Data (Unaudited)

The Partnership's results of operations by quarter for the years ended December 31, 2006 and 2005 were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(Dollars in thousands, except per unit amounts)				
Targa North Texas LP					
Year Ended December 31, 2006:					
Revenues	$ 96,251	$ 92,673	$101,966	$ 93,939	$384,829
Operating income	7,132	6,805	6,996	7,599	28,532
Net loss	(10,229)	(12,951)	(12,244)	(11,486)	(46,910)
Basic income per limited partner unit(a)	—	—	—	—	—
Targa North Texas LP					
Two Months Ended December 31, 2005:					
Revenues	$ —	$ —	$ —	$ 75,144(b)	$ 75,144
Operating income	—	—	—	6,445(b)	6,445
Net loss	—	—	—	(5,097)(b)	(5,097)
Basic income per limited partner unit(a)	—	—	—	—	—
TNT LP Predecessor					
Ten Months Ended October 31, 2005:					
Revenues	$ 71,414	$ 80,280	$ 98,045	$ 43,596(c)	$293,335
Operating income	10,485	12,152	15,445	7,856(c)	45,938
Net income	10,485	12,152	15,445	7,856(c)	45,938
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.

(b) Reflects two months of results.

(c) Reflects one month of results.

Note 14 — Subsequent Event

Initial Public Offering

On February 14, 2007, TNT LP was contributed to TRP LP in conjunction with an IPO of TRP LP's common units. In the IPO, TRP LP issued 19,320,000 common units representing limited partner interests (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) at a price of $21.00 per unit. TRP LP used the net proceeds of the IPO to pay expenses related to the IPO and our credit facility and to repay approximately $371.2 million of our outstanding allocated indebtedness. Upon completion of the IPO, TRP LP had 19,320,000 common units, 11,528,231 subordinated units, and 629,555 general partner units outstanding. The subordinated units and general partner units are indirectly owned by Targa Resources, Inc., or "Targa". To summarize the transactions of the IPO:

- TRP LP issued to Targa 11,528,231 subordinated units, representing a 36.6% limited partner interest;

TARGA NORTH TEXAS LP

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

- TRP LP issued to the general partner, Targa Resources GP LLC, 629,555 general partner units representing an 2% general partner interest in TRP LP, and all of TRP LP's incentive distribution rights, which incentive distribution rights entitle our general partner to increasing percentages of the cash that is distributed in excess of $0.3881 per unit per quarter;
- TRP LP issued 19,320,000 common units to the public in connection with its IPO of common units (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units), representing a 61.4% limited partner interest, and used the proceeds to pay expenses associated with the offering, the formation transactions, and fees associated with our credit facility and paid $371.2 million to Targa to retire a portion of our allocated indebtedness;
- TRP LP borrowed approximately $294.5 million under its $500 million credit facility, the net proceeds of which were paid to Targa to retire an additional portion of our allocated indebtedness; and
- our remaining allocated indebtedness was retired and treated as a capital contribution by Targa.

Our allocated debt from Targa of $864.0 million at December 31, 2006, consisting of allocated indebtedness incurred by Targa and allocated to us for financial reporting purposes as well as allocated indebtedness contributed to us together with the North Texas System was extinguished in conjunction with the sale of common units in TRP LP's IPO, the proceeds from a $500 million credit facility, and a capital contribution from Targa. The following table shows the extinguishment of the allocated debt from Targa (in millions):

Allocated debt from Targa Resources at December 31, 2006		$ 864.0
Gross proceeds from IPO	$405.7	
Discounts, fees and offering expenses	(30.3)	
Fees and expenses of new credit facility	(4.2)	
Net proceeds from offering	$371.2	(371.2)
Net proceeds from new credit facility		(294.5)
Contributed capital from Targa		(198.3)
		$ —

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The following unaudited pro forma financial information presents the results of operations of the North Texas System as if the IPO had been completed on January 1 of the year presented, including a pro forma adjustment to replace interest expense on long-term debt allocated from the Parent with interest expense associated with the credit facility. The pro forma information is not necessarily indicative of the results of operations had the acquisition occurred on January 1 of the year presented or the results of operations that may be obtained in the future.

	Partnership Pro Forma Year Ended December 31, 2006 (Unaudited) (In millions)
Revenues	$ 384.8
Costs and expenses:	
Product purchases	269.3
Operating expense	24.0
Depreciation and amortization expense	56.0
General and administrative expense	6.9
Total costs and expenses	356.2
Income from operations	28.6
Other (income) expense:	
Interest expense allocated from parent	—
Other interest expense	20.6
Deferred income tax expense	2.5
Net income (loss)	$ 5.5
General partner's interest in net income (loss)	$ 0.1
Limited partners' interest in net income (loss)	$ 5.4

TARGA RESOURCES PARTNERS LP

CONSOLIDATED BALANCE SHEETS

	June 30, 2007	December 31, 2006
	(Unaudited) (In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 9,361	$ —
Receivables from third parties	1,195	1,310
Receivables from affiliated companies	50,701	—
Assets from risk management activities	7,616	17,250
Other	483	—
Total current assets	69,356	18,560
Property, plant and equipment, at cost	1,139,723	1,129,210
Accumulated depreciation	(93,586)	(65,102)
Property, plant and equipment, net	1,046,137	1,064,108
Long-term assets from risk management activities	4,462	15,541
Other long-term assets	3,860	17,612
Total assets	$1,123,815	$ 1,115,821
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 4,252	$ 2,789
Accrued liabilities	33,983	28,832
Current maturities of debt allocated from Parent	—	281,083
Liabilities from risk management activities	6,874	—
Total current liabilities	45,109	312,704
Long-term debt allocated from Parent	—	582,877
Long-term debt	294,500	—
Long-term liabilities from risk management activities	11,550	96
Other long-term liabilities	1,763	1,684
Deferred income tax liability	3,197	2,844
Commitments and contingencies (Note 9)		
Partners' capital:		
Common unitholders (19,336,000 units issued and outstanding at June 30, 2007)	378,208	—
Subordinated unitholders (11,528,231 units issued and outstanding at June 30, 2007)	376,673	—
General partner (629,555 units issued and outstanding at June 30, 2007)	20,571	—
Accumulated other comprehensive income (loss)	(7,756)	30,843
Net parent investment	—	184,773
Total partners' capital	767,696	215,616
Total liabilities and partners' capital	$1,123,815	$ 1,115,821

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Unaudited) (In thousands, except per unit amounts)	
Revenues from third parties	$ 10,384	$ 4,728
Revenues from affiliates	189,612	184,196
Total operating revenues	199,996	188,924
Costs and expenses:		
Product purchases from third parties	137,751	132,350
Product purchases from affiliates	514	400
Operating expenses, excluding DD&A	12,033	11,543
Depreciation and amortization expense	28,484	27,439
General and administrative expense	3,531	3,255
	182,313	174,987
Income from operations	17,683	13,937
Other expense:		
Interest expense, net	7,859	—
Interest expense from affiliates, net	9,827	—
Interest expense allocated from Parent	—	35,663
Income (loss) before income taxes	(3)	(21,726)
Deferred income tax expense	665	1,454
Net income (loss)	$ (668)	$ (23,180)
Allocation of net income (loss) for the three and six months ended June 30, 2007:		
Net loss attributable to the period from January 1, 2007 to February 13, 2007	$ (6,861)	
Net income attributable to the period from February 14, 2007 to June 30, 2007	6,193	
Net income (loss)	$ (668)	
General partner interest in net income for the period from February 14, 2007 to June 30, 2007	$ 124	
Common and subordinated unitholders' interest in net income for the period from February 14, 2007 to June 30, 2007	$ 6,069	
Basic net income per common and subordinated unit	$ 0.20	
Diluted net income per common and subordinated unit	$ 0.20	
Basic average number of common and subordinated units outstanding	30,848	
Diluted average number of common and subordinated units outstanding	30,854	

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Unaudited) (In thousands)	
Net income (loss)	$ (668)	$ (23,180)
Other comprehensive income (loss):		
Commodity hedges:		
Change in fair value of commodity hedges	(33,335)	12,007
Reclassification adjustment for settled periods	(5,000)	—
Related income taxes	311	—
Interest rate swaps:		
Change in fair value of interest rate swaps	(575)	1,559
Reclassification adjustment for settled periods	—	3
Other comprehensive income (loss)	(38,599)	13,569
Comprehensive loss	$ (39,267)	$ (9,611)

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL

	Net Parent Investment	Accumulated Other Comprehensive Income	Partners' Capital — Limited Partners — Common	Partners' Capital — Limited Partners — Subordinated	Partners' Capital — General Partner	Total
			(Unaudited) (In thousands)			
Balance at December 31, 2006	$ 184,773	$ 30,843	$ —	$ —	$ —	$215,616
Net loss attributable to the period from January 1, 2007 through February 13, 2007	(6,861)	—	—	—	—	(6,861)
Other contributions	218,993	—	—	—	—	218,993
Book value of net assets contributed by Targa Resources, Inc. to the Partnership	(396,905)	—	—	376,351	20,554	—
Issuance of units to public (including underwriter over-allotment), net of offering and other costs	—	—	377,593	—	—	377,593
Non-cash compensation	—	—	76	—	—	76
Other comprehensive loss	—	(38,599)	—	—	—	(38,599)
Net income attributable to the period from February 14, 2007 to June 30, 2007	—	—	3,802	2,267	124	6,193
Distributions	—	—	(3,263)	(1,945)	(107)	(5,315)
Balance at June 30, 2007	$ —	$ (7,756)	$ 378,208	$ 376,673	$20,571	$767,696

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(Unaudited) (In thousands)	
Cash flows from operating activities		
Net loss	$ (668)	$ (23,180)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation	28,484	27,439
Accretion of asset retirement obligations	79	72
Amortization of debt issue costs	305	2,570
Noncash compensation	76	—
Gain (loss) on sale of assets	1	(15)
Deferred income tax expense	665	1,454
Risk management activities	130	—
Changes in operating assets and liabilities:		
Accounts receivable	(11,730)	409
Inventory	—	824
Other	(503)	630
Accounts payable	1,463	933
Accrued liabilities	5,151	(7,754)
Net cash provided by operating activities	23,453	3,382
Cash flows from investing activities		
Purchases of property, plant and equipment	(10,515)	(11,225)
Other	1	64
Net cash used in investing activities	(10,514)	(11,161)
Cash flows from financing activities		
Proceeds from initial public offering	380,768	—
Costs incurred in connection with initial public offering	(3,175)	—
Distributions	(5,315)	—
Proceeds from borrowings under credit facility	342,500	—
Costs incurred in connection with financing arrangements	(4,145)	—
Repayments of loans:		
Affiliated	(665,692)	—
Credit facility	(48,000)	—
Deemed parent contributions (distributions)	(519)	7,779
Net cash provided by (used in) financing activities	(3,578)	7,779
Net increase in cash and cash equivalents	9,361	—
Cash and cash equivalents, beginning of period	—	—
Cash and cash equivalents, end of period	$ 9,361	$ —
Supplemental cash flow information:		
Net settlement of allocated indebtedness and debt issue costs	$ 846,348	$ —
Net contribution of affiliated indebtedness	(665,692)	—
Net contribution of affiliated receivables	38,856	—
Noncash long-term debt allocation of payments from Parent	—	2,466

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Description of Business and Basis of Presentation

Targa Resources Partners LP (the “Partnership”, “we”, “our”, “us”), a Delaware limited partnership formed in October 2006, currently operates two wholly-owned natural gas processing plants and an extensive network of integrated gathering pipelines that serve a 14 county natural gas producing region in the Fort Worth Basin in North Central Texas (the “North Texas System”). The natural gas processing facilities comprise the Chico processing and fractionating facilities and the Shackelford processing facility.

We closed our initial public offering (“IPO”) of 19,320,000 common units (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) at a price of $21.00 per unit on February 14, 2007. Proceeds from the IPO were approximately $377.6 million, net of offering costs. Concurrent with the IPO, Targa Resources, Inc. (“Targa”) contributed its interest in Targa North Texas GP LLC and Targa North Texas LP (“TNT LP”) to us. In return, Targa indirectly received a 2% general partnership interest in us (629,555 General Partner Units), incentive distribution rights and a 36.6% limited partnership interest in us (11,528,231 Subordinated Units). Our general partner is Targa Resources GP LLC (“TR GP”), a wholly owned subsidiary of Targa. See Note 3 for information related to the distribution rights of the common and subordinated unitholders and the incentive distribution rights held by the general partner.

The accompanying unaudited consolidated financial statements of the Partnership include historical cost-basis accounts of the assets of TNT LP, or the North Texas System, contributed to us by Targa in connection with the IPO for the periods prior to February 14, 2007, the closing date of the Partnership’s IPO, and include charges from Targa for direct costs and allocations of indirect corporate overhead and the results of contracts in force at that time. Management believes that the allocation methods are reasonable, and that the allocations are representative of costs that would have been incurred on a stand-alone basis. Both the Partnership and TNT LP are considered “entities under common control” as defined under accounting principles generally accepted in the United States of America (“GAAP”) and, as such, the transfer between entities of the assets and liabilities and operations has been recorded in a manner similar to that required for a pooling of interests, whereby the recorded assets and liabilities of TNT LP are carried forward to the consolidated partnership at their historical amounts. The Partnership as used herein refers to the consolidated financial results and operations for the North Texas System from its inception through its contribution to us and to the Partnership thereafter.

On February 14, 2007 the Partnership borrowed $342.5 million through 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 also used to repay affiliate indebtedness that was contributed to the Partnership as part of TNT LP. See Note 6 for information related to our credit facility.

Targa directs our business operations through its ownership and control of our general partner. Targa and its affiliates’ employees provide administrative support to us and operate our assets.

These unaudited consolidated financial statements have been prepared in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements, but does not include all disclosures required by GAAP. The unaudited consolidated financial statements for the three and six month periods ended June 30, 2007 and 2006 include all adjustments, both normal and recurring, which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Transactions between us and other Targa operations have been identified in the unaudited consolidated financial statements as transactions between affiliates (see Note 5). Financial results for the Partnership for the three and six months ended June 30, 2007 are not necessarily indicative of the results that may be expected for the full year ended December 31, 2007. These unaudited consolidated financial statements and other information included in this Quarterly Report on Form 10-Q should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2006.

Note 2 — Accounting Policies

Asset Retirement Obligations. The Partnership accounts for asset retirement obligations ("AROs") using Statement of Financial Accounting Standards ("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.

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

Balance as of December 31, 2006	$1,684
Liabilities incurred	—
Change in estimate	—
Accretion expense	79
Balance as of June 30, 2007	$1,763

Cash and Cash Equivalents. 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. 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.

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.

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

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

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. 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 at June 30, 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 U.S. 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 June 30, 2007.

Inventory Imbalance. Quantities of natural gas and/or natural gas liquids ("NGL") 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 NGL. 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 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, NGL 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, the Partnership is paid for its services by keeping a percentage of the NGL extracted and the residue gas resulting from processing natural gas. In percent-of-proceeds arrangements, the Partnership remits either a percentage of the proceeds received from the sales of residue gas and NGL or a percentage of the residue gas or NGL at the tailgate of the plant to the producer. Under the terms of percent-of-proceeds and similar contracts, the Partnership may purchase the producer's share of the processed commodities for resale or deliver the commodities to the producer at the tailgate of the plant. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, the Partnership keeps the NGL extracted and returns to the producer volumes of residue gas containing an equivalent Btu content as the unprocessed natural gas that was delivered to the Partnership. Natural gas or NGL 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 NGL, 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.

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 157, "*Fair Value Measurements*." SFAS 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements, the FASB having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We have not yet determined the impact this new accounting standard will have on our 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.

Note 3 — 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 initially entitled to 2% of all quarterly distributions that we make prior to our liquidation. This general partner interest is represented by 629,555 general partner units. 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 initial 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 the Distributions of Available Cash during the Subordination Period and Distributions of Available Cash after the Subordination Period sections 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, and 2% to the general partner, pro rata, 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, and 2% to the general partner, pro rata, 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, and 2% to the general partner, pro rata, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth*, 98% to all unitholders, and 2% to the general partner, pro rata, until each unitholder receives a total of $0.3881 per unit for that quarter (the First Target Distribution);
- *fifth*, 85% to all unitholders, and 15% to the general partner, 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, and 25% to the general partner, 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, and 50% to the general partner 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, and 2% to the general partner, pro rata, until each unitholder receives a total of $0.3881 per unit for that quarter;
- *second*, 85% to all unitholders, and 15% to the general partner, pro rata, until each unitholder receives a total of $0.4219 per unit for that quarter;
- *third*, 75% to all unitholders, and 25% to the general partner, pro rata, until each unitholder receives a total of $0.50625 per unit for that quarter; and
- *thereafter*, 50% to all unitholders, and 50% to the general partner, pro rata.

Note 4 — 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 pro forma 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. However, because our IPO was completed on February 14, 2007, the number of units issued following the IPO is utilized for the 2007 period presented.

TARGA RESOURCES PARTNERS LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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 common unit was approved by the Board of Directors of our general partner on April 23, 2007. On May 15, 2007, we paid this distribution (approximately $5.3 million) to unitholders of record as of the close of business on May 3, 2007.

The following table illustrates the Partnership's calculation of net income per limited and subordinated partner unit for the six months ended June 30, 2007 (in thousands, except unit and per unit information):

	Six Months Ended June 30, 2007	Feb. 14, 2007 to June 30, 2007	Jan. 1, 2007 to Feb. 13, 2007	Six Months Ended June 30, 2006
Revenues from third parties	$ 10,384	$ 6,449	$ 3,935	$ 4,728
Revenues from affiliates	189,612	151,443	38,169	184,196
	199,996	157,892	42,104	188,924
Costs and expenses:				
Product purchases	138,265	109,570	28,695	132,750
Operating expenses, excluding DD&A	12,033	9,217	2,816	11,543
Depreciation and amortization expense	28,484	21,559	6,925	27,439
General and administrative expense	3,531	2,829	702	3,255
	182,313	143,175	39,138	174,987
Income from operations	17,683	14,717	2,966	13,937
Other expense				
Interest expense, net	7,859	7,859	—	—
Interest expense from affiliate, net	9,827	—	9,827	—
Interest expense allocated from Parent	—	—	—	35,663
Income (loss) before income taxes	(3)	6,858	(6,861)	(21,726)
Deferred income tax expense	665	665	—	1,454
Net income (loss)	$ (668)	$ 6,193	$ (6,861)	$ (23,180)
General partner interest in net income	$ (6,737)	$ 124	$ (6,861)	
Net income available to common and subordinated unitholders	$ 6,069	$ 6,069	$ —	
Basic net income per common and subordinated unit	$ 0.20	$ 0.20		
Diluted net income per common and subordinated unit	$ 0.20	$ 0.20		
Basic average number of common and subordinated units outstanding	30,848	30,848		
Restrictive equivalents	6	6		
Diluted average number of common and subordinated units outstanding	30,854	30,854		

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.

Note 5 — 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 9, 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 assets contributed to us in connection with our IPO. Specifically, 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.

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.

Sales to and purchases from affiliates. The Partnership routinely conducts business with other subsidiaries of Targa. The related transactions result primarily from purchases and sales of natural gas and NGL. 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, these transactions are settled monthly in cash.

NGL and Condensate Purchase Agreement. In connection with our IPO which closed on February 14, 2007, we entered into an NGL and high pressure condensate purchase agreement with Targa Liquids Marketing and Trade ("TLMT") 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 NGL (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.

Natural Gas Purchase Agreement. In connection with our IPO which closed on February 14, 2007, we entered into a natural gas purchase agreement with Targa Gas Marketing LLC ("TGM") at a price based on TGM's sale price for such natural gas, less TGM's costs and expenses associated therewith. This agreement 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. Furthermore, either party may elect to terminate the agreement if either party ceases to be an affiliate of Targa.

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 February 14, 2007, these allocations were not settled in cash, but were settled through an adjustment to partners' capital accounts. Effective February 14, 2007, all intercompany accounts are settled monthly 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 Dynegy Midstream Services, Limited Partnership (the "DMS Acquisition") 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. On January 1, 2007, the allocated debt, debt issue costs and interest rate swaps were settled through a deemed partner contribution of $846.3 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.

	Six Months Ended June 30, 2007	Feb. 14, 2007 to June 30, 2007	Jan. 1, 2007 to Feb. 13, 2007	Six Months Ended June 30, 2006
	(In thousands)			
Cash				
Sales to affiliates	$ (189,612)	$ (151,443)	$ (38,169)	$ (184,196)
Purchases from affiliates	514	437	77	400
Allocations of general & administrative expenses — pre IPO	702	—	702	3,255
Allocations of general & administrative expenses under Omnibus Agreement	2,829	2,829	—	—
Allocated interest	—	—	—	35,663
Affiliate interest	9,838	—	9,838	—
Receivable from affiliates to be settled in cash	50,701	50,701	—	—
Payments made by the Parent	124,509	97,476	27,033	150,163
	$ (519)	$ —	(519)	5,285
Noncash				
Net settlement of allocated indebtedness and debt issue costs			$ 846,348	$ —
Net contribution of affiliated indebtedness			(665,692)	—
Other			38,856	2,466
			219,512	2,466
			$ 218,993	$ 7,751

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 June 30, 2007:

Period	Commodity	Instrument Type	Daily Volumes	Average Price	Index
Jul 2007 — Dec 2007	Natural gas	Swap	4,200 MMBtu	$ 9.14 per MMBtu	IF-Waha
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
Jul 2007 — Dec 2007	NGL	Swap	500 Bbl	37.80 per Bbl	OPIS-MB
Jan 2008 — Dec 2008	NGL	Swap	375 Bbl	36.75 per Bbl	OPIS-MB
Jan 2009 — Dec 2009	NGL	Swap	300 Bbl	35.39 per Bbl	OPIS-MB
Jul 2007 — Dec 2007	Condensate	Swap	319 Bbl	75.27 per Bbl	NY-WTI
Jan 2008 — Dec 2008	Condensate	Swap	264 Bbl	72.66 per Bbl	NY-WTI
Jan 2009 — Dec 2009	Condensate	Swap	202 Bbl	70.60 per Bbl	NY-WTI
Jan 2010 — Dec 2010	Condensate	Swap	181 Bbl	69.28 per Bbl	NY-WTI

Note 6 — Debt

In October 2005, Targa completed the DMS acquisition. 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 $868.9 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 annum). The Partnership 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.

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 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 June 30, 2007 was 6.9%.

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 5.75 to 1.00, as of June 30, 2007; and 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 June 30, 2007, we had approximately $205.5 million available under our revolving credit facility, after giving effect to our outstanding borrowings.

Note 7 — Derivative Instruments and Hedging Activities

At June 30, 2007 and December 31, 2006, OCI included $7.8 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 three and six months ended June 30, 2007, deferred net gains on commodity hedges of $1.0 million and $5.0 million were reclassified from OCI and credited to income as revenues. There were no settlements of commodity hedges during the first six months of 2006. There were no adjustments for hedge ineffectiveness during the first six months of 2007 or 2006.

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 three and six months ended June 30, 2006, deferred net gains (losses) on interest rate hedges of $36,000 and ($3,000) were reclassified from OCI to net interest expense. There were no adjustments for hedge ineffectiveness during the first six months of 2007 or 2006.

At June 30, 2007, deferred net gains of $35,000 on commodity hedges recorded in OCI are expected to be reclassified to earnings during the next twelve months.

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At June 30, 2007, we had the following hedge arrangements for the six months ended December 31, 2007 and the years ended December 31, 2008 thru 2012:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per Day 2007	2008	2009	2010	2011	2012	Fair Value (In thousands)
Swap	IF-NGPL MC	$8.56	8,152	—	—	—	—	—	$2,975
Swap	IF-NGPL MC	8.43	—	6,964	—	—	—	—	2,644
Swap	IF-NGPL MC	8.02	—	—	6,256	—	—	—	340
Swap	IF-NGPL MC	7.43	—	—	—	5,685	—	—	(713)
Swap	IF-NGPL MC	7.34	—	—	—	—	2,750	—	(181)
Swap	IF-NGPL MC	7.18	—	—	—	—	—	2,750	(90)
			8,152	6,964	6,256	5,685	2,750	2,750	4,975
Swap	IF-Waha	8.73	5,460	—	—	—	—	—	1,836
Swap	IF-Waha	8.53	—	4,657	—	—	—	—	1,102
Swap	IF-Waha	7.96	—	—	4,196	—	—	—	(177)
Swap	IF-Waha	7.38	—	—	—	3,809	—	—	(659)
Swap	IF-Waha	7.36	—	—	—	—	2,250	—	(200)
Swap	IF-Waha	7.18	—	—	—	—	—	2,250	(136)
			5,460	4,657	4,196	3,809	2,250	2,250	1,766
Total Swaps			13,612	11,621	10,452	9,494	5,000	5,000	6,741
Floor	IF-NGPL MC	6.45	520	—	—	—	—	—	56
Floor	IF-NGPL MC	6.55	—	1,000	—	—	—	—	259
Floor	IF-NGPL MC	6.55	—	—	850	—	—	—	186
			520	1,000	850	—	—	—	501
Floor	IF-Waha	6.70	350	—	—	—	—	—	37
Floor	IF-Waha	6.85	—	670	—	—	—	—	168
Floor	IF-Waha	6.55	—	—	565	—	—	—	113
			350	670	565	—	—	—	318
Total Floors			870	1,670	1,415	—	—	—	819
									$7,560

NGL

Instrument Type	Index	Avg. Price $/MMBtu	Barrels per Day 2007	2008	2009	2010	2011	2012	Fair Value (In thousands)
Swap	OPIS-MB	$0.96	3,416	—	—	—	—	—	$ (3,375)
Swap	OPIS-MB	0.93	—	2,910	—	—	—	—	(5,136)
Swap	OPIS-MB	0.89	—	—	2,548	—	—	—	(2,863)
Swap	OPIS-MB	0.87	—	—	—	2,159	—	—	(1,718)
Swap	OPIS-MB	0.90	—	—	—	—	1,250	—	(262)
Swap	OPIS-MB	0.90	—	—	—	—	—	750	69
			3,416	2,910	2,548	2,159	1,250	750	$(13,285)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per Day 2007	2008	2009	2010	2011	2012	Fair Value (In thousands)
Swap	NY-WTI	$72.82	439	—	—	—	—	—	$ 126
Swap	NY-WTI	70.68	—	384	—	—	—	—	(223)
Swap	NY-WTI	69.00	—	—	322	—	—	—	(356)
Swap	NY-WTI	68.10	—	—	—	301	—	—	(274)
Total Swaps			439	384	322	301	—	—	(727)
Floor	NY-WTI	58.60	25	—	—	—	—	—	2
Floor	NY-WTI	60.50	—	55	—	—	—	—	48
Floor	NY-WTI	60.00	—	—	50	—	—	—	56
Total Floors			25	55	50	—	—	—	106
			464	439	372	301	—	—	$(621)

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 revenues on the hedged volumes than we would receive in the absence of hedges.

Note 8 — Income Taxes

We are not a taxable entity for U.S. 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 $0.3 million and $0.7 million for the three and six months ended June 30, 2007, was computed by applying a 1.0% state income tax rate to taxable margin, as defined in the Texas statute.

Note 9 — Commitments and Contingencies

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 June 30, 2007, primarily for ground water assessment and remediation.

Under the Omnibus Agreement described in Note 5, 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 Summary

The Partnership is not a party to any legal proceeding other than legal proceedings arising in the ordinary course of its business. The Partnership is a party to various administrative and regulatory proceedings that have arisen in the ordinary course of its business which are not expected to have a material adverse effect upon our future financial position, results of operations or cash flows.

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 5.

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 10 — Employees and Equity Compensation Plans

We do not directly employ any of the persons responsible for managing our business, nor do we have a compensation committee. Any compensation decisions that are required to be made by our general partner, TR GP, are made by its board of directors. All of our executive officers are employees of Targa Resources LLC, a wholly-owned subsidiary of Targa. All of the outstanding equity of Targa is held indirectly by Targa Resources Investments Inc. ("Targa Investments"). Our reimbursement for the compensation of executive officers is 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 Omnibus Agreement.

Equity Compensation Plans.

Our general partner has adopted a long-term incentive plan ("LTIP") for employees, consultants and directors of our general partner and its affiliates who perform services for us, including officers, directors and employees of Targa. The LTIP provides for the grant of restricted units, phantom units, unit options and substitute awards, and with respect to unit options and phantom units, the grant of distribution equivalent rights ("DERs"). Under the LTIP, up to 1.68 million common units may be delivered pursuant to awards under the LTIP. The LTIP is administered by the board of directors of Targa Resources GP LLC, and may be delegated to the compensation committee of the board of directors of our general partner if one is established. Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to cash distributions paid on an outstanding common unit. Upon vesting, certain of the awards may be settled in common units or equivalent cash at the election of our general partner. For the three and six months ended June 30, 2007, we recognized compensation expense of approximately $85,000 and $115,000 related to the LTIP, respectively.

In connection with our IPO in February 2007, we made equity-based awards to each of our non-management and independent directors under our LTIP. We also made equity-based awards to each of the non-management and independent directors of Targa Investments. The awards were determined by Targa Investments and were ratified by the board of directors of our general partner. Each of our independent and non-management directors and the independent and non-management directors of Targa Investments received an initial award of 2,000 restricted units, for a total of 16,000 restricted units. The awards to these independent and non-management directors consist of restricted units and will settle with the delivery of common units. All of these awards are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant. For the three months ended June 30, 2007 and for the period from commencement of Partnership operations (February 14, 2007) through June 30, 2007, we recognized compensation expense of approximately $60,000 and $76,000 related to the equity-based awards, respectively. We estimate that the remaining fair value of $0.3 million will be recognized in expense over the next 32 months.

Note 11 — Subsequent Event

On July 23, 2007, our general partner approved a quarterly distribution of available cash of $0.3375 per unit (approximately $10.6 million), for the quarter ended June 30, 2007, payable on August 14, 2007 to unitholders of record as of the close of business on August 2, 2007.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of Directors of Targa Resources, Inc.:

In our opinion, the accompanying combined balance sheets and the related combined statements of operations and comprehensive income, of changes in parent investment and of cash flows present fairly, in all material respects, the combined financial position of the SAOU and LOU Systems of Targa Resources, Inc. at December 31, 2006 and 2005, and the combined results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the management of Targa Resources, Inc.; 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 auditing standards generally accepted in the United States of America, which 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 financial statements, the SAOU and LOU Systems of Targa Resources, Inc. have engaged in significant transactions with other subsidiaries of their parent company, Targa Resources, Inc.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
September 27, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Targa Resources, Inc.

We have audited the accompanying combined statements of operations and comprehensive income, changes in parent investment, and cash flows of SAOU and LOU Systems of Targa Resources, Inc. (the "Combined Entities") for the period March 12, 2004 (inception) through December 31, 2004. These financial statements are the responsibility of the Combined Entities' management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Combined Entities' internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Combined Entities' internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the combined results of the operations and the cash flows of SAOU and LOU Systems of Targa Resources, Inc. for the period March 12, 2004 (inception) through December 31, 2004, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas
September 28, 2007

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SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

COMBINED BALANCE SHEETS

	December 31, 2006	December 31, 2005
	(In thousands)	
ASSETS (Collateral for Parent Debt — See Note 5)		
Current assets:		
Trade receivables	$ 60,249	$138,501
Inventory	958	1,176
Assets from risk management activities	8,433	1,140
Other current assets	—	477
Total current assets	69,640	141,294
Property, plant and equipment, at cost:	262,433	252,974
Accumulated depreciation	(37,970)	(24,095)
Property, plant and equipment, net	224,463	228,879
Debt issue costs allocated from Parent	3,741	4,775
Long-term assets from risk management activities	310	95
Other long-term assets	2,396	2,141
Total assets (Collateral for Parent Debt — See Note 5)	$300,550	$377,184
LIABILITIES AND PARENT INVESTMENT		
Current liabilities:		
Accounts payable	$ 984	$ 15,376
Accrued liabilities	80,505	92,535
Liabilities from risk management activities	3,296	12,231
Current maturities of debt allocated from Parent	59,664	1,047
Other current liabilities	—	1,615
Total current liabilities	144,449	122,804
Long-term debt allocated from Parent	123,720	183,384
Long-term liabilities from risk management activities	455	8,215
Other long-term liabilities	1,235	1,103
Deferred income tax liability	394	—
Commitments and contingencies (Note 6)		
Parent investment:		
Parent investment	30,176	67,229
Accumulated other comprehensive income (loss)	121	(5,551)
Total Parent investment	30,297	61,678
Total liabilities and Parent investment	$300,550	$377,184

See notes to combined financial statements

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

COMBINED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

	SAOU and LOU Systems of Targa Resources, Inc.		
	Year Ended December 31,		March 12 (Inception) through December 31,
	2006	2005	2004
		(In thousands)	
Revenues from third parties	$ 953,468	$1,076,746	$ 603,947
Revenues from affiliates	416,984	8,587	—
Total operating revenues	1,370,452	1,085,333	603,947
Costs and expenses:			
Product purchases from third parties	926,264	986,705	543,453
Product purchases from affiliates	322,071	19,987	1,434
Operating expense, excluding DD&A	24,973	20,900	15,253
Depreciation and amortization expense	13,999	13,919	10,394
General and administrative expense	9,159	15,658	11,149
	1,296,466	1,057,169	581,683
Income from operations	73,986	28,164	22,264
Other expense:			
Loss on debt extinguishment	—	(3,701)	—
Interest expense allocated from Parent	(15,115)	(9,635)	(6,108)
Income before income taxes	58,871	14,828	16,156
Income tax expense (benefit):			
Current	—	—	—
Deferred	394	—	—
	394	—	—
Net income	58,477	14,828	16,156
Other comprehensive income (loss):			
Commodity hedges:			
Change in fair value	1,748	(16,870)	746
Reclassification adjustment for settled periods	3,788	10,436	151
Interest rate hedges			
Change in fair value	220	(21)	—
Reclassification adjustment for settled contracts	(84)	7	—
	5,672	(6,448)	897
Comprehensive income	$ 64,149	$ 8,380	$ 17,053

See notes to combined financial statements

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SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

COMBINED STATEMENTS OF CHANGES IN PARENT INVESTMENT

SAOU and LOU Systems of Targa Resources, Inc.	Parent Investment	Accumulated Other Comprehensive	Total
		(In thousands)	
Initial contribution	$ 126,135	$ —	$126,135
Distributions	(3,965)	—	(3,965)
Net income	16,156	—	16,156
Other comprehensive income	—	897	897
Balance, December 31, 2004	138,326	897	139,223
Distributions	(85,925)	—	(85,925)
Net income	14,828	—	14,828
Other comprehensive loss	—	(6,448)	(6,448)
Balance, December 31, 2005	67,229	(5,551)	61,678
Distributions	(95,530)	—	(95,530)
Net income	58,477	—	58,477
Other comprehensive income	—	5,672	5,672
Balance, December 31, 2006	$ 30,176	$ 121	$ 30,297

See notes to combined financial statements

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

COMBINED STATEMENTS OF CASH FLOWS

	SAOU and LOU Systems of Targa Resources, Inc.		
	Year Ended December 31,		March 12 (Inception) through December 31,
	2006	2005	2004
	(In thousands)		
Cash flows from operating activities			
Net income	$ 58,477	$ 14,828	$ 16,156
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation	13,874	13,795	10,300
Amortization of intangibles	125	124	94
Amortization of debt issue costs	1,092	3,875	884
Accretion	101	59	40
Deferred income tax expense (benefit)	394	—	—
(Gain) loss on mark-to-market derivative contracts	(16,757)	11,973	(1,305)
Changes in operating assets and liabilities:			
Trade receivables	78,252	(61,766)	(76,735)
Inventory	218	(795)	(381)
Other assets	477	—	(477)
Accounts payable	(14,392)	12,284	3,092
Accrued and other current liabilities	(13,645)	17,611	76,539
Net cash provided by operating activities	108,216	11,988	28,207
Cash flows from investing activities			
Purchases of property, plant and equipment	(9,458)	(5,063)	(2,850)
Other	(349)	414	—
Net cash used in investing activities	(9,807)	(4,649)	(2,850)
Cash flows from financing activities			
Distributions to parent	(98,409)	(7,339)	(25,357)
Net cash used in financing activities	(98,409)	(7,339)	(25,357)
Net increase in cash and cash equivalents	—	—	—
Cash and cash equivalents, beginning of period	—	—	—
Cash and cash equivalents, end of period	$ —	$ —	$ —
Supplemental cash flow information:			
Noncash investing and financing activities:			
Property, plant and equipment allocated from Parent	$ —	$ —	$ 245,061
Intangible assets	—	—	2,359
Debt issue costs allocated from Parent	58	6,229	3,305
Asset retirement obligations	—	—	(590)
Long-term debt allocated from Parent:			
Borrowing	—	(227,106)	(147,944)
Repayment	1,047	145,675	44,944

See notes to combined financial statements

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS

Note 1 — Organization and Operations of the Partnership

Organization. The combined financial statements of the SAOU and LOU Systems of Targa Resources, Inc. (the "SAOU and LOU Systems", "us", "our" or "we") include the accounts of Targa Texas Field Services LP ("TTFS"), a Delaware partnership, and Targa Louisiana Field Services LLC ("TLFS"), a Delaware limited liability company, each formed on March 12, 2004. The combined entities commenced commercial operations on April 16, 2004, with the purchase from ConocoPhillips of certain midstream natural gas assets located in West Texas and in Louisiana (See Note 3 — Acquisition of Assets from ConocoPhillips presented in these financial statements as "Predecessor").

Both TTFS and TLFS are indirect wholly-owned subsidiaries of Targa Resources, Inc. ("Targa Resources"). Targa Resources manages our operations and employs our officers and personnel (See Note 7 — Related Party Transactions).

The accompanying combined financial statements are presented on a carve-out combined basis to include the historical operations of TTFS and TLFS. In this context, no direct owner relationship existed among the operations comprising the SAOU and LOU Systems as described above. Accordingly, Targa Resources' net investment in us (Parent investment) is shown in lieu of partner's capital or member's capital in the combined financial statements.

Basis of Presentation. The accompanying combined financial statements and related combined notes present our combined financial position as of December 31, 2006 and 2005, and the results of our combined operations, combined cash flows and combined changes in parent investment for the years ended December 31, 2006 and 2005 and for the period from March 12, 2004 through December 31, 2004.

Throughout the periods covered by the combined financial statements, Targa Resources has provided cash management services to the SAOU and LOU Systems through a centralized treasury system. As a result, all of the SAOU and LOU Systems' charges and cost allocations covered by the centralized treasury system were deemed to have been paid to Targa Resources in cash, during the period in which the cost was recorded in the combined financial statements. In addition, cash receipts advanced by Targa Resources in excess/deficit of charges and cash allocations are reflected as contributions from/distributions to Targa Resources in the combined statements of changes in parent investment. As a result of this accounting treatment, the SAOU and LOU Systems' working capital does not reflect any affiliate accounts receivable for intercompany commodity sales or any affiliate accounts payable for personnel, intercompany product purchases or allocated debt from the parent. Consequently, the SAOU and LOU Systems had a combined negative working capital balance of $74.8 million at December 31, 2006. Despite the negative working capital balance, on a combined basis, the SAOU and LOU Systems generated operating cash flow of $108.2 million for the year ended December 31, 2006. Such cash flow was sufficient to fund investing cash flow of $9.8 million and distributions to Targa Resources of $98.4 million during the period.

Operations. We provide midstream energy services, including gathering, treating, and processing services, to producers of natural gas in West Texas and the Louisiana Gulf Coast region. Our gathering systems collect natural gas from designated points near producing wells and transport these volumes to our gas processing plants. Natural gas shipped to our gas processing plants is treated to remove contaminants and processed to yield residue natural gas and raw natural gas liquids ("NGL"). We fractionate some of the raw NGL into separate component products, including ethane, propane, iso- and normal-butane, and natural gasoline. We deliver residue natural gas and NGL directly for sale to customers and to pipeline interconnects for sale to markets.

Note 2 — Significant Accounting Policies

Asset Retirement Obligations. We account for asset retirement obligations in accordance with Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 143, "*Accounting for Asset Retirement Obligations*." SFAS 143 requires entities to record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred. A legal obligation is a liability that a party is required to settle as a result of an existing or enacted law, statute, ordinance or contract. When the liability is initially recorded, the entity is required to capitalize the retirement cost of the related long-lived asset. Each period the liability is accreted to its then present value, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. We adopted SFAS 143 at the time of our acquisition of the assets from ConocoPhillips on April 16, 2004 (See Note 3).

In March 2005, the FASB issued Financial 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, "Accounting for Asset Retirement Obligations." 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 of our control. 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.

The following table reflects the changes in our asset retirement obligation during the periods shown.

	SAOU and LOU Systems of Targa Resources, Inc.		
	For the Years December 31,		March 12 (Inception) Ended December 31,
	2006	2005	2004
		(In thousands)	
Asset retirement obligations — beginning of period	$1,103	$ 630	$ —
Liabilities incurred	—	—	590
Change in estimate	—	414	—
Accretion	101	59	40
Asset retirement obligations — end of period	$1,204	$ 1,103	$ 630

Cash and Cash Equivalents. 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 us 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. In addition, we monitor and review our credit exposure to end users and marketing counterparties. Letters of credit or other appropriate security or payment terms are obtained as considered necessary to limit the risk of loss. Our exposure is also mitigated by existing netting arrangements.

Credit limits are established through a process of reviewing the financial history and stability of each customer. We regularly evaluate the collectibility of our trade receivable balances by monitoring past-due balances. If it is determined that a customer will be unable to meet its financial obligation, we record a specific allowance for bad debts to reduce the related receivable to the amount we expect to recover. We had no recorded allowance for bad debts at either December 31, 2006 or 2005.

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

Significant Commercial Relationships. Prior to 2006, our natural gas and NGL sales and purchase transactions were primarily with third parties. In late 2005, we began selling and purchasing natural gas from affiliated entities. In 2006, we began selling and purchasing NGL in addition to natural gas through affiliated entities. For the year ended December 31, 2006, there were no counterparties that represented more than 10% of our revenues or product purchases.

For the year ended December 31, 2005, transactions with PPG, Enterprise Products and CITGO represented approximately 14%, 13% and 12% of our combined revenues, respectively. No other counterparty accounted for more than 10% of our revenues or product purchases during 2005.

For the period March 12 (Inception) through December 31, 2004, transactions with ConocoPhillips, Enterprise Products, PPG, and CITGO represented approximately 17%, 16%, 16%, and 12%, respectively, of our combined revenues and transactions with Newfield Exploration and Cimarex Energy represented approximately 12% and 10%, respectively, of our product purchases. No other counterparty accounted for more than 10% of our revenues or product purchases during the period March 12 (Inception) through December 31, 2004.

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

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

Income Taxes. Both TTFS and TLFS are treated as pass-through entities for income tax purposes. Earnings or losses for federal income tax purposes are included in the tax returns of the individual partners/member of the limited partnership and the member of the limited liability company. In May 2006, Texas adopted a margin tax consisting of a 1% tax on the amount by which total revenue exceeds cost of goods. Accordingly, we have estimated our liability for this tax.

Intangible Assets. Intangible assets consist of the value of customer and supplier contracts and relationships obtained in the acquisition from ConocoPhillips. These assets are amortized over the estimated useful lives of the related gathering systems on a straight-line basis. Amortization expense was $0.1 million for each of the years ended December 31, 2006 and 2005 and the period March 12 (Inception) through December 31, 2004.

We review intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. This review consists of comparing the carrying value of the asset with the asset's expected future undiscounted cash flows. Estimates of expected future cash flows represent management's best estimate based on reasonable and supportable assumptions. If such a review should indicate that the carrying amount of intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value.

Inventories. Product inventories consist primarily of NGL. Most product inventories turn over monthly and are valued at the lower of cost or market using the average cost method.

Natural Gas Imbalances. Quantities of natural gas over-delivered or under-delivered related to operational balancing agreements are recorded monthly as inventory using weighted average prices at the time the imbalance was created. Monthly, gas imbalances receivable are valued at the lower of cost or market; gas imbalances payable are valued at replacement cost. These imbalances are typically settled in the following month with deliveries or receipts of natural gas. 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.

Price Risk Management (Hedging). We account 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 parent investment, and reclassified to earnings when the forecasted transaction occurs. The fair value of our commodity 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 or quoted on the New York Mercantile Exchange. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

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

Our policy is to formally document all relationships between hedging instruments and hedged items, as well as 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, we assess whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Hedge effectiveness is measured on a quarterly basis. Any ineffective portion of the unrealized gain or loss is reclassified to earnings in the current period.

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

Asset Group	Range of Years
Natural gas gathering systems and processing facilities	10 to 25
Office and miscellaneous equipment	5

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. 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. If the carrying amount exceeds the expected future undiscounted cash flows we recognize an impairment loss to write down the carrying amount of the asset to its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our Statements of Operations and Comprehensive Income.

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

- sales of natural gas, NGL and condensate; and
- natural gas processing, from which we generate revenue through the compression, gathering, treating, and processing of natural gas.

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

For processing services, we receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under percent-of-proceeds contracts, we are paid for our services by keeping a percentage of the NGL extracted and the residue gas resulting from processing natural gas. In percent-of-proceeds arrangements, we remit either a percentage of the proceeds received from the sales of residue gas and NGL or a percentage of the residue gas or NGL at the tailgate of the plant to the producer. Under the terms of percent-of-proceeds and similar contracts, we may purchase the producer's share of the processed commodities for resale or deliver the commodities to the producer at the tailgate of the plant. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, we keep the NGL extracted and return the processed natural gas or value of the natural gas to the producer. Natural gas or NGL that we receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee based contracts, we receive a fee based on throughput volumes.

We generally report revenues gross in the 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, we act as the principal in the transactions where we receive commodities, take title to the natural gas and NGL, and incur the risks and rewards of ownership.

Segment Information. SFAS 131, "*Disclosures about Segments of an Enterprise and Related Information*," establishes standards for reporting information about operating segments. We operate in one segment only, the natural gas gathering and processing segment.

Use of Estimates. The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires management to make estimates and judgments that affect our reported financial position and results of operations. We review significant estimates and judgments affecting our financial statements on a recurring basis and record the effect of any necessary adjustments prior to their publication. 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 our assets and

(5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results could differ materially from estimated amounts.

Recent Accounting Pronouncements.

In December 2004, the FASB released its final revised standard entitled SFAS 123(R), "*Share-Based Payment*," which significantly changed accounting practice with respect to employee stock options and other stock based compensation. SFAS 123(R) requires companies to recognize, as an operating expense, the estimated fair value of share-based payments to employees, including grants of employee stock options. Because we do not have any employees, our adoption of SFAS 123(R) on January 1, 2006 was only affected by the allocation of stock-based compensation cost by our Parent. Such allocation did not have a material effect on our financial statements.

In September 2005, the FASB ratified the consensus on EITF 04-13, "*Accounting for Purchases and Sales of Inventory With the Same Counterparty*." EITF 04-13 relates to an entity that may sell inventory to another entity in the same line of business from which it also purchases inventory. This guidance is effective for new (including renegotiated or modified) inventory arrangements entered into in the first interim or annual reporting period beginning after March 15, 2006. Our adoption of EITF 04-13 on April 1, 2006 had no effect on our financial statements.

In July 2006, the FASB issued Interpretation 48, "*Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109*" ("FIN 48"), which clarifies the accounting and disclosure for uncertainty in income taxes recognized in an enterprise's financial statements. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement related to accounting for income taxes. This interpretation is effective for fiscal years beginning after December 15, 2006. Based on our evaluation, we have determined that there will be no significant uncertain tax positions requiring recognition in our financial statements at the date of adoption. There also will be 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.

In September 2006, the FASB issued SFAS 157, "*Fair Value Measurements*." SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles ("GAAP"), and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements, the Board having previously concluded in these accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We have not yet determined the impact this statement will have on our results of operations or financial position.

We adopted the guidance in Securities and Exchange Commission ("SEC") Staff Accounting Bulletin 108 ("SAB 108"). Due to diversity in practice among registrants, SAB 108 expresses SEC staff views regarding the process by which misstatements in financial statements are evaluated for purposes of determining whether financial statement restatement is necessary. SAB 108 had no effect on our results of operations or financial position.

In February 2007, the FASB issued SFAS 159, "*The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of 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.

Note 3 — Acquisition of Assets from ConocoPhillips

In April 2004, Targa Resources purchased various midstream assets located in West Texas and the Louisiana Gulf Coast region from ConocoPhillips for approximately $247 million in cash, including certain acquisition-related costs.

The assets purchased consisted of an integrated gathering and processing system with low and high-pressure lines, gathering natural gas from various wellhead and central delivery locations in the Permian Basin in West Texas, covering parts of eight counties from San Angelo to Big Spring, Texas, as well as an integrated gathering and processing system covering approximately 2,000 square miles from Lake Charles to Lafayette, Louisiana.

The following presents the portion of the purchase price and related long-term debt and debt issue costs allocated to the combined assets based on the estimated fair values of the assets acquired and the liabilities assumed (in thousands):

Property, plant and equipment	$ 245,061
Intangible assets	2,359
Debt issue costs	3,305
Long-term debt	(124,000)
Asset retirement obligations	(590)
Initial contribution	$ 126,135

Note 4 — Property, Plant and Equipment

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

	December 31, 2006	December 31, 2005
	(In thousands)	
Gathering and processing systems	$249,181	243,591
Other property and equipment	13,252	9,383
	262,433	252,974
Accumulated depreciation	(37,970)	(24,095)
	$224,463	$228,879

Note 5 — Long-Term Debt

Our long-term debt, all of which has been allocated to us from Targa Resources, consisted of the following at the dates indicated:

	December 31, 2006	December 31, 2005
	(In thousands)	
Senior secured term loan facility, variable rate, due October 2012	$103,363	$104,410
Senior secured asset sale bridge loan facility, variable rate, due October 2007	58,616	58,616
Senior secured notes, 8.5% fixed rate due November 2013	21,405	21,405
	183,384	184,431
Less current maturities of debt	(59,664)	(1,047)
Long-term debt	$123,720	$183,384

Allocation of Long-Term Debt from the Parent

Targa Resources' debt was allocated to identifiable asset groups which collateralize the debt based on the fair value of the acquired assets. The collateralization base includes all of Targa Resources' assets and equity interests.

On February 14, 2007, the senior secured asset sale bridge loan was paid in full with the proceeds from Targa Resources Partners LP's ("TRP") initial public offering and borrowings from TRP's credit facility.

The following table presents information regarding variable interest rates paid on Targa Resources' debt for the year ended December 31, 2006:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Senior secured term loan facility	6.59% to 7.75%	7.03%
Senior secured asset sale bridge loan facility	6.83% to 7.62%	7.26%

Interest expense on long-term debt allocated to us is settled through an adjustment to Parent investment (see Note 7 — Related-Party Transactions).

Debt Maturity Table

The following table presents the scheduled maturities of principal amounts of Targa Resources long-term debt allocated to us as of December 31, 2006 (in thousands):

2007	$ 59,664
2008	1,047
2009	1,047
2010	1,047
2011	1,047
Thereafter	119,532
	$183,384

Description of Parent Debt Obligations

Senior Secured Credit Facility

On October 31, 2005, Targa Resources entered into a $2,500 million senior secured credit agreement with a syndicate of financial institutions and other institutional lenders. The credit agreement includes a $300 million senior secured letter of credit facility.

Borrowings under the senior secured credit agreement, other than the senior secured synthetic letter of credit facility, bear interest at a rate equal to an applicable margin plus, at Targa Resources option, either: (a) a base rate determined by reference to the higher of (1) the prime rate of Credit Suisse and (2) the federal funds rate plus $^1/_2$ of 1% or (b) LIBOR as determined by reference to the costs of funds for dollar deposits for the interest period relevant to such borrowing adjusted for certain statutory reserves. The initial applicable margin for borrowings under the senior secured revolving credit facility is 1.25% with respect to base rate borrowings and 2.25% with respect to LIBOR borrowings. After repayment of the senior secured asset sale bridge loan facility, the margin for borrowings under the senior secured revolving credit facility is 1.00% with respect to base rate borrowings and 2.00% with respect to LIBOR borrowings. The applicable margin for borrowings under the senior secured revolving credit facility may fluctuate based upon Targa Resources' leverage ratio as defined in the credit agreement.

Targa Resources is required to pay a facility fee, quarterly in arrears, to the lenders under the senior secured synthetic letter of credit facility equal to (i) 2.25% per annum of the amount on deposit in the designated deposit account plus (ii) the administrative cost incurred by the deposit account agent for such quarterly period.

In addition to paying interest on outstanding principal under the senior secured credit facilities, Targa Resources is required to pay a commitment fee equal to 0.50% per annum of the currently unutilized commitments thereunder. The commitment fee rate may fluctuate based upon its leverage ratios.

All obligations under Targa Resources' senior secured credit agreement and certain secured hedging arrangements are unconditionally guaranteed, subject to certain exceptions, by each of its existing and future domestic restricted subsidiaries, including us.

All obligations under the senior secured credit facilities and certain secured hedging arrangements, and the guarantees of those obligations, are secured by substantially all of the following assets, subject to certain exceptions:

- a pledge of our general partner and limited partner interests; and
- a security interest in, and mortgages on, our tangible and intangible assets.

8$^1/_2$% Senior Notes due 2013

On October 31, 2005 Targa Resources completed the private placement of $250 million in aggregate principal amount of senior unsecured notes ("the Notes").

Interest on the Notes accrues at the rate of 8$^1/_2$% per annum and is payable in arrears on May 1 and November 1. Interest is computed on the basis of a 360-day year comprising twelve 30-day months. Additional interest may accrue on the Notes in certain circumstances pursuant to a registration rights agreement.

The Notes are Targa Resources' unsecured senior obligations, and are guaranteed by us, subordinate to our guarantee of Targa Resources' borrowings under its senior secured credit facility.

Interest Rate Swaps

In connection with its Senior Secured Credit Facility, Targa Resources entered into interest rate swaps for a notional amount of $350 million. The interest rate swaps effectively fix the interest rate on $350 million in borrowings under the Senior Secured Credit Facility to a rate of 4.8% plus the applicable LIBOR margin (2.25% at December 31, 2006) through November 2007.

The change in fair value of the interest rate swaps, together with the related accumulated other comprehensive income and interest expense has been allocated to us in the same proportion as the allocation of Targa Resources' borrowings under its Senior Secured Credit Facility.

Note 6 — Commitments and Contingencies

Surface and underground access for gathering, processing, and distribution assets that are located on property not owned by us is obtained through right-of-way agreements, which require annual rental payments and expire at various dates through 2099. Future non-cancelable commitments related to these obligations are presented below (in thousands):

	Total	2007	2008	2009	2010	2011	Thereafter
Right of way	$1,081	$243	$179	$148	$137	$123	$ 251

Total expenses related to right-of-way agreements were $450,000 in 2006, $294,000 in 2005 and $239,000 in the period March 12 through December 31, 2004.

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 TTFS , and two other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips and Morgan Stanley, tortuously 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 SAOU System and its successful acquisition of those assets in 2004. Discovery is proceeding. A hearing on Targa's motion for summary judgment was held on April 10, 2007. Targa intends to contest liability but can give no assurances regarding the outcome of the proceeding. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit.

Environmental

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated in accordance with the American Institute of Certified Public Accountants ("AICPA") Statement of Position No. 96-1, "*Environmental Remediation Liabilities*" ("SOP 96-1"). 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.

Prior to our purchase of the Acadia plant site and other assets from ConocoPhillips, the Acadia plant site, located in Louisiana, was identified as having benzene, toluene, ethyl benzene and xylene contamination, collectively ("BTEX"). The BTEX contamination was reported by ConocoPhillips to the Louisiana Department of Environmental Quality ("LDEQ") who identified ConocoPhillips as a potentially responsible party. ConocoPhillips has begun remediation activities in coordination with the LDEQ, and is negotiating a cooperative agreement with the LDEQ regarding environmental assessment and remedial activities at the site. Under the terms of our purchase and sales agreement, ConocoPhillips retains the liability for the BTEX remediation and for all third party costs or claims relating to, arising out of, or connected with corrective actions/remediation of the BTEX contamination. As a result, we have not recorded a liability for environmental remediation as it relates to the BTEX contamination.

We have not recorded any liability for environmental matters for the periods ended December 31, 2006 or 2005.

Note 7 — Related Party Transactions

Sales to and purchases from affiliates. We routinely conduct business with other subsidiaries of our parent. The related transactions result primarily from purchases and sales of natural gas and natural gas liquids. In addition, all of our expenditures are paid through our parent company resulting in intercompany transactions. Unlike sales transactions with third parties that settle in cash, settlement of these sales transactions occurs through adjustments to Parent investment.

Allocation of costs. The employees supporting our operations are employees of Targa Resources. Our financial statements include costs allocated to us by Targa Resources for centralized general and administrative services performed by them, as well as depreciation of assets utilized by Targa Resources centralized general and administrative functions. Costs were allocated to us based on our proportionate share of Targa Resources' assets, revenues and employees. Costs allocated to us were based on identification of our resources which directly benefit us and our proportionate share of costs based on our estimated usage of shared resources and functions. All of the allocations are based on assumptions that management believes are reasonable; however, these allocations are not necessarily indicative of the costs and expenses that would have resulted if we had operated as a stand-alone entity. These allocations are not settled in cash. Settlement of these allocations occurs through adjustments to Parent investment.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. Our financial statements include long-term debt, debt issue costs, interest rate swaps and interest expense allocated from Targa Resources. The allocations were calculated in a manner based on the fair value of tangible assets. These allocations are not settled in cash. Settlement of these allocations occurs through an adjustment to Parent investment.

The following table summarizes the sales to and purchases from affiliates of Targa Resources, payments made or received by them on our behalf, and allocations of costs from them which are settled through an adjustment to Parent investment. Management believes these transactions were executed on fair and reasonable terms.

	SAOU and LOU Systems of Targa Resources, Inc.		
	Year Ended December 31,		March 12 (Inception) through December 31,
	2006	2005	2004
	(In thousands)		
Cash			
Sales to affiliates	$(416,984)	$ (8,587)	$ —
Purchases from affiliates	322,071	19,987	1,434
Allocations of general & administrative expenses (G&A) expenses	9,159	15,658	11,149
Allocated interest	15,115	9,635	6,108
Payments made by (to) the Parent	(27,770)	(44,032)	(44,048)
	(98,409)	(7,339)	(25,357)

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

	SAOU and LOU Systems of Targa Resources, Inc.		
	Year Ended December 31,		March 12 (Inception) through December 31,
	2006	2005	2004
	(In thousands)		
Non-cash			
Initial contribution by Parent (see Note 3)	$ —	$ —	$ 126,135
Parent payment of debt payments	1,047	145,675	44,944
Net contribution (distribution) of affiliate indebtedness and debt issue costs	58	(220,877)	(23,944)
Parent settlement of risk management activities	1,774	(3,384)	392
Other	—	—	—
	2,879	(78,586)	147,527
Transactions settled through adjustments to partners' capital	$ (95,530)	$ (85,925)	$ 122,170

Centralized cash management. Targa Resources operates a cash management system whereby excess cash from most of its various subsidiaries, held in separate bank accounts, is swept to a centralized account. Cash distributions are deemed to have occurred through Parent investment and are reflected as adjustments to Parent investment. Deemed net distributions of cash to Targa Resources were $98.4 million and $7.3 million for the years ended December 31, 2006 and 2005 and $25.4 million for the period March 12 (Inception) through December 31, 2004.

On December 16, 2004, Targa Resources acquired a 40% ownership interest in Bridgeline Holdings, L.P. ("Bridgeline"). Targa Resources sold its interest in Bridgeline on August 5, 2005. For the period from January 1, 2005 to August 5, 2005, our natural gas sales and purchase activity with Bridgeline was $8.6 million in sales and $20.0 million in purchases, respectively. For the period from December 16, 2004 to December 31, 2004, we had $1.4 million in natural gas purchases from Bridgeline. The market prices with Bridgeline were consistent with those of nonaffiliated entities.

Note 8 — Derivative Instruments and Hedging Activities

At December 31, 2006, OCI consisted of $121,000 of unrealized gains on interest rate hedges allocated from Targa Resources.

At December 31, 2005, OCI consisted of $5.5 million of unrealized net losses on commodity hedges and $14,000 of unrealized gains on interest rate hedges allocated from Targa Resources.

During the years ended December 31, 2006 and 2005 and the period March 12 (Inception) through December 31, 2004, deferred net losses on commodity hedges of $3.8 million, $10.4 million and $0.2 million, respectively, were reclassified from OCI and charged to income as a decrease in revenues. During the years ended December 31, 2006 and 2005, a deferred gain of $84,000 and a deferred loss of $7,000, respectively, were reclassified from OCI and charged or credited to income as adjustments to interest expense.

Targa has entered into numerous derivative contracts that have been designated as hedges of certain of our forecasted transactions, but we were not a direct party to the derivative contracts. As such, we are not entitled to hedge accounting treatment under SFAS 133. Accordingly, all unrealized gains and losses on the allocated derivatives have been recorded in the combined statement of operations as a component of third party operating revenues, and these derivatives are settled through an adjustment to parent equity (See Note 7).

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

During the years ended December 31, 2006 and 2005, and the period March 12 (Inception) through December 31, 2004, we recognized noncash mark-to-market gains and (losses) of $16.8 million, $(12.0) million and $1.3 million, respectively, on commodity derivatives not designated as hedges.

We have interest rate swaps with a notional amount of $29.3 million that have been allocated to us. The interest rate swaps effectively fix the interest rate on Targa Resources $350 million in borrowings under its senior secured term loan facility to a rate of 4.8% plus the applicable LIBOR margin (2.25% at December 31, 2006) through November 2007. At December 31, 2006, the fair value of the interest rate swaps allocated to us was $0.1 million, which is included in OCI and expected to be reclassified to earnings during the next twelve months.

At December 31, 2006, we had the following open commodity derivatives:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per Day 2007	2008	2009	Fair Value (In thousands)
Swap	IF-HSC	$ 9.08	2,740	—	—	$ 2,370
Swap	IF-HSC	8.09	—	2,328	—	272
Swap	IF-HSC	7.39	—	—	1,966	(128)
			2,740	2,328	1,966	2,514
Swap	IF-Waha	$ 8.42	2,740	—	—	2,005
Swap	IF-Waha	7.64	—	2,732	—	38
Swap	IF-Waha	7.08	—	—	2,740	(252)
			2,740	2,732	2,740	1,791
Total Swaps			5,480	5,060	4,706	4,305
Basis Swap Jan 2007 Rec IF-HH minus $0.01, pay GD-HH, 899,000 MMBtu						7
						$ 4,312

NGLs

Instrument Type	Index	Avg. Price $/gal	Barrels per Day 2007	2008	2009	Fair Value (In thousands)
Swap	OPIS-MB	$ 0.88	1,751			$ 740
Swap	OPIS-MB	0.84		1,600		141
Swap	OPIS-MB	0.81			1,300	(249)
			1,751	1,600	1,300	$ 632

These commodity derivatives have not been designated as hedges. They were entered into by Targa Resources to hedge our anticipated operational volumes.

Customer Derivatives

Period	Commodity	Instrument Type	Daily Volumes	Average Price	Index	Fair Value (In thousands)
Purchases						
Jan 2007 — Dec 2007	Natural gas	Swap	6,382 MMBtu	$7.94 per MMBtu	NY-HH	$ (3,296)
Sales						
Jan 2007 — Dec 2007	Natural gas	Fixed price sale	6,382 MMBtu	$7.91 per MMBtu	—	3,223
						$ (73)

These are commodity derivative contracts directly related to short-term fixed price arrangements elected by certain customers in various natural gas purchase and sale agreements. They have been marked to market.

The following table shows the balance sheet classification of the fair value of our open commodity derivatives and allocated interest rate swaps at the dates indicated (in thousands):

	December 31, 2006	December 31, 2005
Current assets	$ 8,433	$ 1,140
Noncurrent assets	310	95
Current liabilities	(3,296)	(12,231)
Noncurrent liabilities	(455)	(8,215)
	$ 4,992	$ (19,211)

Note 9 — Income Taxes

TTFS and TLFS are not taxable entities for U.S. Federal income tax purposes. Income tax liabilities that are generated by our operations are borne by our indirect corporate owner. In May 2006, Texas substantially revised its tax rules and imposed a new tax based on modified gross income 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 $0.4 million for the year ended December 31, 2006, was computed by applying a 1.0% Texas state income tax rate to taxable margin, as defined in the Texas statute.

Note 10 — Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate in the midstream energy industry. Our business activities include gathering, transporting and processing of natural gas, NGL and crude oil. As such, our results of operations, cash flows and financial condition may be affected by (i) changes in the commodity prices of these hydrocarbon products and (ii) changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGL, 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, NGL 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, NGL and crude oil handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made with

NGL products, (iii) increased competition from petroleum-based products due to the pricing differences, (iv) adverse weather conditions, (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could also adversely affect our results of operations, cash flows and financial position.

Counterparty Risk with Respect to Financial Instruments

Where we are exposed to credit risk in our financial instrument transactions, management analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit and/or margin limits and monitors the appropriateness of these limits on an ongoing basis. Generally, management does not require collateral and does not anticipate non-performance by our counterparties.

Casualties or Other Risks

Targa Resources 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 Resources 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 Resources 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 combined 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 our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our financial obligations.

Note 11 — Subsequent Event

During September 2007, Targa entered into the following commodity derivatives for a portion of our production:

Period	Commodity	Type	Daily Volumes	Average Price	Index
Nov '07 — Dec '07	NGL	Swap	3,351 Bbls	$ 1.18 per gallon	MB-OPIS
Jan'08 — Dec '08	NGL	Swap	3,300 Bbls	1.06 per gallon	MB-OPIS
Jan'09 — Dec '09	NGL	Swap	3,200 Bbls	0.99 per gallon	MB-OPIS
Jan'10 — Dec '10	NGL	Swap	1,600 Bbls	0.93 per gallon	MB-OPIS
Jan'11 — Dec '11	NGL	Swap	1,100 Bbls	0.91 per gallon	MB-OPIS
Jan'12 — Dec '12	NGL	Swap	900 Bbls	0.92 per gallon	MB-OPIS

In addition, Targa terminated the following commodity derivatives that were allocated to us as of December 31, 2006. During 2007, we will recognize a noncash mark-to-market loss of $10.6 million with respect to such terminated commodity derivatives.

Period	Commodity	Type	Daily Volumes	Average Price	Index
Nov '07 — Dec '07	NGL	Swap	1,751 Bbls	$ 0.88 per gallon	MB-OPIS
Jan'08 — Dec '08	NGL	Swap	1,600 Bbls	0.84 per gallon	MB-OPIS
Jan'09 — Dec '09	NGL	Swap	1,300 Bbls	0.81 per gallon	MB-OPIS

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

COMBINED BALANCE SHEETS

	June 30, 2007	December 31, 2006
	(In thousands)	
	(Unaudited)	
ASSETS (Collateral for Parent Debt — See Note 4)		
Current assets:		
Trade receivables	$ 56,016	$ 60,249
Inventory	1,228	958
Assets from risk management activities	3,848	8,433
Total current assets	61,092	69,640
Property, plant, and equipment, at cost	275,270	262,433
Accumulated depreciation	(45,081)	(37,970)
Property, plant, and equipment, net	230,189	224,463
Debt issue costs allocated from Parent	3,010	3,741
Long-term assets from risk management activities	282	310
Other long-term assets	2,335	2,396
Total assets (Collateral for Parent Debt — See Note 4)	$ 296,908	$ 300,550
LIABILITIES AND PARENT INVESTMENT		
Current liabilities:		
Accounts payable	$ 2,193	$ 984
Accrued liabilities	87,903	80,505
Liabilities from risk management activities	10,616	3,296
Current maturities of debt allocated from Parent	1,047	59,664
Total current liabilities	101,759	144,449
Long-term debt allocated from Parent	123,199	123,720
Long-term liabilities from risk management activities	12,556	455
Other long-term liabilities	1,329	1,235
Deferred income tax liability	436	394
Commitments and contingencies (Note 6)		
Parent investment:		
Parent investment	57,552	30,176
Accumulated other comprehensive income	77	121
Total Parent investment	57,629	30,297
Total liabilities and Parent Investment	$ 296,908	$ 300,550

See notes to unaudited combined financial statements

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

COMBINED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(In thousands) (Unaudited)	
Revenues from third parties	$283,953	$616,605
Revenues from affiliates	277,445	180,448
Total operating revenues	561,398	797,053
Costs and expenses:		
Product purchases from third parties	426,868	519,928
Product purchases from affiliates	101,066	213,790
Operating expense, excluding DD&A	11,914	12,281
Depreciation and amortization expense	7,173	6,729
General and administrative expense	4,450	2,092
Gain on sale of assets	(315)	—
	551,156	754,820
Income from operations	10,242	42,233
Other expense:		
Interest expense allocated from Parent, net	(4,887)	(7,416)
Income before income taxes	5,355	34,817
Deferred income tax expense	42	394
Net income	5,313	34,423
Other comprehensive income (loss):		
Commodity hedges:		
Change in fair value	—	3,029
Reclassification adjustment for settled contracts	—	614
Interest rate hedges:		
Change in fair value	44	325
Reclassification adjustment for settled contracts	(88)	1
Other comprehensive income (loss)	(44)	3,969
Comprehensive income	$ 5,269	$ 38,392

See notes to unaudited combined financial statements

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

COMBINED STATEMENTS OF CHANGES IN PARENT INVESTMENT

	Parent Investment	Accumulated Other Comprehensive Income (Loss)	Total
		(In thousands) (Unaudited)	
Balance at December 31, 2006	$ 30,176	$ 121	$30,297
Contributions	22,063	—	22,063
Net income	5,313	—	5,313
Other comprehensive income	—	(44)	(44)
Balance at June 30, 2007	$ 57,552	$ 77	$57,629

See notes to unaudited combined financial statements

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SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

COMBINED STATEMENTS OF CASH FLOW

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
	(In thousands) (Unaudited)	
Cash flows from operating activities		
Net income	$ 5,313	$ 34,423
Adjustments to reconcile net income to cash flows provided by operating activities:		
Depreciation	7,112	6,667
Amortization of debt issue costs	731	490
Amortization of intangibles	61	62
Accretion	125	51
(Gain) loss on mark-to-market derivative contracts	21,002	(8,399)
Gain on sale of assets	(315)	—
Deferred taxes	42	394
Risk management activities	(44)	—
Changes in operating assets and liabilities:		
Trade receivable	4,548	68,127
Inventory	(270)	417
Other assets	—	103
Accounts payable	1,209	(16,103)
Accrued liabilities	7,397	(17,653)
Net cash provided by operating activities	46,911	68,579
Cash flows from investing activities		
Purchases of property, plant and equipment	(12,837)	(5,964)
Other	(31)	—
Net cash used in investing activities	(12,868)	(5,964)
Cash flows from financing activities		
Distributions to parent	(34,043)	(62,615)
Net cash used in financing activities	(34,043)	(62,615)
Net increase in cash and cash equivalents	—	—
Cash and cash equivalents, beginning of period	—	—
Cash and cash equivalents, end of period	$ —	$ —
Supplemental cash flow information:		
Long-term debt allocated from Parent:		
Repayments	$ 59,138	$ 523

See notes to unaudited combined financial statements

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS

Note 1 — Organization and Operations of the Partnership

Organization. The unaudited combined financial statements of the SAOU and LOU Systems of Targa Resources, Inc. (the "SAOU and LOU Systems", "us", "our" or "we") include the accounts of Targa Texas Field Services LP ("TTFS"), a Delaware partnership, and Targa Louisiana Field Services LLC ("TLFS"), a Delaware limited liability company, each formed on March 12, 2004. The combined entities commenced commercial operations on April 16, 2004, with the purchase from ConocoPhillips of certain midstream natural gas assets located in West Texas and in Louisiana.

Both TTFS and TLFS are indirect wholly-owned subsidiaries of Targa Resources, Inc. ("Targa Resources"). Targa Resources manages our operations and employs our officers and personnel (See Note 6 — Related Party Transactions).

Basis of Presentation. The accompanying unaudited combined financial statements are presented on a carve-out combined basis to include the historical operations of TTFS and TLFS. In this context, no direct owner relationship existed among the operations comprising the SAOU and LOU Systems as described above. Accordingly, Targa Resources' net investment in us (Parent investment) is shown in lieu of partner's capital or member's capital in the combined financial statements.

The accompanying unaudited combined financial statements and related combined notes present our combined financial position as of June 30, 2007 and December 31, 2006, and the results of our combined operations, combined cash flows and combined changes in parent investment for the six months ended June 30, 2007 and 2006 and have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial statements. The year-end balance sheet was derived from audited financial statements, but does not include all disclosures required by GAAP for complete combined financial statements. The unaudited interim combined financial information for the six month periods ended June 30, 2007 and 2006 include all adjustments, both normal and recurring, which are, in the opinion of management, necessary for a fair presentation of the results for the interim periods. All significant intercompany balances and transactions have been eliminated in combination. Transactions between us and other Targa affiliates have been identified in the unaudited interim combined financial statements as transactions between affiliates (see Note 6 — Related Party Transactions). Financial results for the combined entities for the six months ended June 30, 2007 are not necessarily indicative of the results that may be expected for the full year. These unaudited interim combined financial statements should be read in conjunction with the audited combined financial statements and notes thereto in the annual report for the year ended December 31, 2006.

Throughout the periods covered by the combined financial statements, Targa Resources has provided cash management services to the SAOU and LOU Systems through a centralized treasury system. As a result, all of the SAOU and LOU Systems' charges and cost allocations covered by the centralized treasury system were deemed to have been paid to Targa Resources in cash, during the period in which the cost was recorded in the combined financial statements. In addition, cash receipts advanced by Targa Resources in excess/deficit of charges and cash allocations are reflected as contributions from/distributions to Targa Resources in the combined statements of changes in parent investment. As a result of this accounting treatment, the SAOU and LOU Systems' working capital does not reflect any affiliate accounts receivable for intercompany commodity sales or any affiliate accounts payable for personnel and intercompany product purchases. Consequently, the SAOU and LOU Systems had a combined negative working capital balance of $40.7 million at June 30, 2007. Despite the negative working capital balance, on a combined basis, the SAOU and LOU Systems generated operating cash flow of $46.9 million for the six months ended June 30, 2007. Such cash flow was sufficient to fund investing cash flow of $12.9 million and distributions to Targa Resources of $34.0 million during the period.

Operations. We provide midstream energy services, including gathering, treating, and processing services, to producers of natural gas in West Texas and the Louisiana Gulf Coast region. Our gathering systems collect natural gas from designated points near producing wells and transport these volumes to our gas processing plants. Natural gas shipped to our gas processing plants is treated to remove contaminants and processed to yield residue natural gas and raw natural gas liquids ("NGL"). We fractionate some of the raw NGL into separate component products, including ethane, propane, iso- and Normal-butane, and natural gasoline. We deliver residue natural gas and NGL directly for sale to customers and to pipeline interconnects for sale to markets.

Note 2 — Accounting Policies and Related Matters

Income Taxes. We are not subject to federal or state income taxes. As a result, our earnings or losses for tax purposes are included in the tax returns of our parent. 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. In these financial statements, we have estimated our liability for this tax as if we were a stand-alone company separate from our parent 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. If we were a stand-alone company separate from our parent, based on our evaluation, we have determined that there would be no significant uncertain tax positions that would require recognition in our financial statements at the date of adoption or at June 30, 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.

Recent Accounting Pronouncements. In September 2006, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") 157 *"Fair Value Measurements."* SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles ("GAAP"), and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements, the Board having previously concluded in these accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We have not yet determined the impact this statement will have on our results of operations or financial position.

In February 2007, the FASB issued SFAS 159, *"The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of 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.

Note 3 — Asset Retirement Obligations

Under the provisions of SFAS 143, "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. The changes in our aggregate asset retirement obligations are as follows (in thousands):

Balance as of December 31, 2006	$1,204
Liabilities incurred	—
Change in estimate	—
Accretion	125
Balance as of June 30, 2007	$1,329

Note 4 — Debt

Our long-term debt, all of which has been allocated to us from Targa Resources, consisted of the following at the dates indicated.

	June 30, 2007	December 31, 2006
	(In thousands)	
Senior secured term loan facility, variable rate, due October 2012	$102,841	$ 103,363
Senior secured asset sale bridge loan facility, variable rate, due October 2007(1)	—	58,616
Senior unsecured notes, 8.5% fixed rate, due November 2013	21,405	21,405
	124,246	183,384
Less current maturities of debt	(1,047)	(59,664)
Long-term debt	$123,199	$ 123,720

(1) The entire amount was repaid in February 2007 concurrent with the closing of the initial public offering of Targa Resources Partners LP.

Allocation of Long-Term Debt from the Parent

Targa Resources' debt was allocated to identifiable asset groups which collateralize the debt based on the fair value of the acquired assets. The collateralization base includes all of Targa Resources' assets and equity interests. The following table presents information regarding variable interest rates paid on Targa Resources' debt for the six months ended June 30, 2007:

	Range of Interest Rates Paid	Weighted Average Interest Rate Paid
Senior secured term loan facility	7.36% - 7.62%	7.53%
Senior secured asset sale bridge loan facility	7.60%	7.60%

Interest expense on long-term debt allocated to us is settled through an adjustment to Parent investment (see Note 6 — Related Party Transactions).

Debt Maturity Table

The following table presents the scheduled maturities of principal amounts of Targa Resources' long-term debt allocated to us as of June 30, 2007 (in thousands):

2007	$ 524
2008	1,047
2009	1,047
2010	1,047
2011	1,047
Thereafter	119,534
	$124,246

Description of Parent Debt Obligations

Senior Secured Credit Facility

On October 31, 2005, Targa Resources entered into a $2,500 million senior secured credit agreement with a syndicate of financial institutions and other institutional lenders. The credit agreement includes a $300 million senior secured letter of credit facility.

Borrowings under the senior secured credit agreement, other than the senior secured synthetic letter of credit facility, bear interest at a rate equal to an applicable margin plus, at Targa Resources' option, either: (a) a base rate determined by reference to the higher of (1) the prime rate of Credit Suisse and (2) the federal funds rate plus $^1/_2$ of 1% or (b) LIBOR as determined by reference to the costs of funds for dollar deposits for the interest period relevant to such borrowing adjusted for certain statutory reserves. The current applicable margin for borrowings under the senior secured revolving credit facility is 1.0% with respect to base rate borrowings and 2.0% with respect to LIBOR borrowings. The applicable margin for borrowings under the senior secured revolving credit facility may fluctuate based upon Targa Resources' leverage ratio as defined in the credit agreement.

Targa Resources is required to pay a facility fee, quarterly in arrears, to the lenders under the senior secured synthetic letter of credit facility equal to (i) 2.0% of the amount on deposit in the designated deposit account plus (ii) the administrative cost incurred by the deposit account agent for such quarterly period.

In addition to paying interest on outstanding principal under the senior secured credit facilities, Targa Resources is required to pay a commitment fee equal to 0.50% per annum of the currently unutilized commitments thereunder. The commitment fee rate may fluctuate based upon its leverage ratios.

All obligations under Targa Resources' senior secured credit agreement and certain secured hedging arrangements are unconditionally guaranteed, subject to certain exceptions, by each of its existing and future domestic restricted subsidiaries, including us.

All obligations under the senior secured credit facilities and certain secured hedging arrangements, and the guarantees of those obligations, are secured by substantially all of the following assets, subject to certain exceptions:

- a pledge of our general partner and limited partner interests; and
- a security interest in, and mortgages on, our tangible and intangible assets.

8$^{1}/_{2}$% Senior Notes due 2013

On October 31, 2005 Targa Resources completed the private placement of $250 million in aggregate principal amount of senior unsecured notes (“the Notes”).

Interest on the Notes accrues at the rate of 8$^{1}/_{2}$% per annum and is payable in arrears on May 1 and November 1. Interest is computed on the basis of a 360-day year comprising twelve 30-day months. Additional interest may accrue on the Notes in certain circumstances pursuant to a registration rights agreement.

The Notes are Targa Resources’ unsecured senior obligations, and are guaranteed by us, subordinate to our guarantee of Targa Resources’ borrowings under its senior secured credit facility.

Interest Rate Swaps

In connection with its Senior Secured Credit Facility, Targa Resources entered into interest rate swaps for a notional amount of $350 million. The interest rate swaps effectively fix the interest rate on $350 million in borrowings under the Senior Secured Credit Facility to a rate of 4.8% plus the applicable LIBOR margin (2.0% at June 30, 2007) through November 2007.

The change in fair value of the interest rate swaps, together with the related accumulated other comprehensive income and interest expense has been allocated to us in the same proportion as the allocation of Targa Resources’ borrowings under its Senior Secured Credit Facility.

Note 5 — Commitments and Contingencies

Litigation Summary

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 TTFS, and two other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips and Morgan Stanley, tortuously 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 SAOU System and its successful acquisition of those assets in 2004. Discovery is proceeding. A hearing on Targa’s motion for summary judgment was held on April 10, 2007. Targa intends to contest liability but can give no assurances regarding the outcome of the proceeding. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit (see Note 9 — Subsequent Events).

Environmental

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated in accordance with the American Institute of Certified Public Accountants (“AICPA”) Statement of Position No. 96-1, “*Environmental Remediation Liabilities*” (“SOP 96-1”). 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.

Prior to our purchase of the Acadia plant site and other assets from ConocoPhillips, the Acadia plant site, located in Louisiana, was identified as having benzene, toluene, ethyl benzene and xylene contamination, collectively (“BTEX”). The BTEX contamination was reported by ConocoPhillips to the Louisiana Department of Environmental Quality (“LDEQ”) who identified ConocoPhillips as a potentially responsible party. ConocoPhillips has begun remediation activities in coordination with the LDEQ, and is negotiating a cooperative agreement with the LDEQ regarding environmental assessment and remedial activities at the site. Under the terms of our purchase and sales agreement, ConocoPhillips retains the liability for the BTEX remediation and for all third party costs or claims relating to, arising out of, or connected with corrective actions/remediation of the BTEX contamination. As a result, we have not recorded a liability for environmental remediation as it relates to the BTEX contamination.

We have not recorded any liability for environmental matters for the period ended June 30, 2007.

Note 6 — Related Party Transactions

Sales to and purchases from affiliates. We routinely conduct business with other subsidiaries of our parent. The related transactions result primarily from purchases and sales of natural gas and natural gas liquids. In addition, all of our expenditures are paid through our parent company resulting in intercompany transactions. Unlike sales transactions with third parties that settle in cash, settlement of these sales transactions occurs through adjustments to Parent investment.

Allocation of costs. The employees supporting our operations are employees of Targa Resources. Our financial statements include costs allocated to us by Targa Resources for centralized general and administrative services performed by them, as well as depreciation of assets utilized by Targa Resources centralized general and administrative functions. Costs were allocated to us based on our proportionate share of Targa Resources' assets, revenues and employees. Costs allocated to us were based on identification of our resources which directly benefit us and our proportionate share of costs based on our estimated usage of shared resources and functions. All of the allocations are based on assumptions that management believes are reasonable; however, these allocations are not necessarily indicative of the costs and expenses that would have resulted if we had operated as a stand-alone entity. These allocations are not settled in cash. Settlement of these allocations occurs through adjustments to Parent investment.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. Our financial statements include long-term debt, debt issue costs, interest rate swaps and interest expense allocated from Targa Resources. The allocations were calculated in a manner based on the fair value of tangible assets. These allocations are not settled in cash. Settlement of these allocations occurs through an adjustment to Parent investment.

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

The following table summarizes the sales to and purchases from affiliates of Targa Resources, payments made or received by them on our behalf, and allocations of costs from them which are settled through an adjustment to Parent investment. Management believes these transactions were executed on terms that are fair and reasonable.

	For the Six Months Ended June 30, 2007	For the Six Months Ended June 30, 2006
Cash		
Sales to affiliates	$ (277,445)	$ (180,448)
Purchases from affiliates	101,066	213,790
Allocations of general and administrative (G&A) expenses	4,450	2,092
Allocated interest	4,887	7,416
Payments made by (to) the Parent	132,999	(105,465)
	(34,043)	(62,615)
Non-cash		
Parent payment of debt payments	59,138	523
Parent settlement of risk management activities	(3,032)	723
	56,106	1,246
Transactions settled through adjustments to parent investment	$ 22,063	$ (61,369)

Centralized cash management. Targa Resources operates a cash management system whereby excess cash from most of its various subsidiaries, held in separate bank accounts, is swept to a centralized account. Cash distributions are deemed to have occurred through Parent investment and are reflected as adjustments to Parent investment. Deemed net distributions of cash to Targa Resources were $34.0 million and $62.6 million for the six months ended June 30, 2007 and 2006.

Note 7 — Derivative Instruments and Hedging Activities

At June 30, 2007 and December 31, 2006, OCI consisted of $77,000 and $121,000, respectively, of unrealized gains on interest rate hedges allocated from Targa Resources.

During the six months ended June 30, 2007, deferred gains on interest rate hedges of $88,000 were reclassified from OCI and credited to income as a reduction in interest expense.

During the six months ended June 30, 2006, deferred net losses on commodity hedges of $0.6 million were reclassified from OCI and charged to expense as a reduction in revenues and deferred net losses on interest rate hedges of $1,000 were reclassified from OCI and charged to expense as an increase in interest expense.

Targa has entered into numerous derivative contracts that have been designated as hedges of certain of our forecasted transactions, but we were not a direct party to the derivative contracts. As such, we are not entitled to hedge accounting treatment under SFAS 133. Accordingly, all unrealized gains and losses on the allocated derivatives have been recorded on the combined statement of operations as a component of third party operating revenues.

During the six months ended June 30, 2007 and 2006, we recognized a net loss of $21.0 million and a net gain of $8.4 million, respectively, on commodity derivatives not designated as hedges.

SAOU AND LOU SYSTEMS OF TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

At June 30, 2007, our open commodity derivatives consisted of the following:

Instrument Type	Index	Average Price $/MMBtu	MMBtu per Day 2007	2008	2009	2010	2011	2012	Fair Value (In thousands)
Swap	IF-HSC	$9.08	2,740	—	—	—	—	—	$ 925
Swap	IF-HSC	8.09	—	2,328	—	—	—	—	(34)
Swap	IF-HSC	7.39	—	—	1,966	—	—	—	(595)
			2,740	2,328	1,966	—	—	—	296
Swap	IF-Waha	$8.42	$2,740	—	—	—	—	—	765
Swap	IF-Waha	7.64	—	2,732	—	—	—	—	(201)
Swap	IF-Waha	7.08	—	—	2,740	—	—	—	(906)
Swap	IF-Waha	7.37	—	—	—	1,900	—	—	(331)
Swap	IF-Waha	7.36	—	—	—	—	1,000	—	(89)
Swap	IF-Waha	7.18	—	—	—	—	—	1,000	(60)
			2,740	2,732	2,740	1,900	1,000	1,000	(822)
Total Swaps			5,480	5,060	4,706	1,900	1,000	1,000	$ (526)

Instrument Type	Index	Average Price $/gallon	Barrels per Day 2007	2008	2009	2010	2011	2012	Fair Value (In thousands)
Swap	OPIS-MB	$0.85	2,851	—	—	—	—	—	$ (4,127)
Swap	OPIS-MB	0.81	—	2,800	—	—	—	—	(7,776)
Swap	OPIS-MB	0.78	—	—	2,700	—	—	—	(5,460)
Swap	OPIS-MB	0.82	—	—	—	1,650	—	—	(1,110)
Swap	OPIS-MB	0.84	—	—	—	—	750	—	(144)
Swap	OPIS-MB	0.84	—	—	—	—	—	550	24
			2,851	2,800	2,700	1,650	750	550	$ (18,593)

These derivatives have not been designated as hedges. They were entered into by Targa Resources to hedge our anticipated operational volumes.

Customer Derivatives

Period	Commodity	Instrument Type	Daily Volume	Average Price	Index	Fair Value (In thousands)
Purchases						
Jul 2007 — Dec 2007	Natural gas	Swap	11,159 MMBtu	$6.12 per MMBtu	NY-HH	$ 90
Sales						
Jul 2007 — Dec 2007	Natural gas	Fixed price sale	11,159 MMBtu	$6.12 per MMBtu	—	(90)
						$ —

These are commodity derivative contracts directly related to short-term fixed price arrangements elected by certain customers in various natural gas purchase and sale agreements. They have been marked to market.

We also have interest rate swaps with a notional amount of $30.0 million that have been allocated to us. The interest rate swaps effectively fix the interest rate on $350 million of Targa Resources' borrowings under its senior secured term loan facility to a rate of 4.8% plus the applicable LIBOR margin (2.00% at June 30,

2007) through November 2007. At June 30, 2007, the fair value of the interest rate swaps allocated to us was $0.1 million.

The following table shows the balance sheet classification of the fair value of our open commodity derivatives and allocated interest rate swaps at the dates indicated (in thousands):

	June 30, 2007	December 31, 2006
Current assets	$ 3,848	$ 8,433
Noncurrent assets	282	310
Current liabilities	(10,616)	(3,296)
Noncurrent liabilities	(12,556)	(455)
	$ (19,042)	$ 4,992

Note 8 — Income Taxes

TTFS and TLFS are not taxable entities for U.S. Federal income tax purposes. Income tax liabilities that are generated by our operations are borne by our indirect corporate owner. In May 2006, Texas substantially revised its tax rules and imposed a new tax based on modified gross income 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 $0.4 million for the six months ended June 30, 2007 and $0.3 million for the six months ended June 30, 2006, was computed by applying a 1.0% Texas state income tax rate to taxable margin, as defined in the Texas statute.

Note 9 — Subsequent Events

Commodity Derivatives

During September 2007, Targa entered into the following commodity derivatives for a portion of our production:

Period	Commodity	Type	Daily Volumes	Average Price	Index
Nov '07 — Dec '07	NGL	Swap	3,351 Bbls	$ 1.18 per gallon	MB-OPIS
Jan'08 — Dec '08	NGL	Swap	3,300 Bbls	1.06 per gallon	MB-OPIS
Jan'09 — Dec '09	NGL	Swap	3,200 Bbls	0.99 per gallon	MB-OPIS
Jan'10 — Dec '10	NGL	Swap	1,600 Bbls	0.93 per gallon	MB-OPIS
Jan'11 — Dec '11	NGL	Swap	1,100 Bbls	0.91 per gallon	MB-OPIS
Jan'12 — Dec '12	NGL	Swap	900 Bbls	0.92 per gallon	MB-OPIS

In addition, Targa terminated the following commodity derivatives that were allocated to us as of June 30, 2007. During the the three months ended September 30, 2007, we will recognize a noncash mark-to-market loss of $8.3 million with respect to such terminated commodity derivatives.

Period	Commodity	Type	Daily Volumes	Average Price	Index
Nov '07 — Dec '07	NGL	Swap	2,851 Bbls	$ 0.86 per gallon	MB-OPIS
Jan'08 — Dec '08	NGL	Swap	2,800 Bbls	0.81 per gallon	MB-OPIS
Jan'09 — Dec '09	NGL	Swap	2,700 Bbls	0.78 per gallon	MB-OPIS
Jan'10 — Dec '10	NGL	Swap	1,100 Bbls	0.80 per gallon	MB-OPIS
Jan'11 — Dec '11	NGL	Swap	200 Bbls	0.81 per gallon	MB-OPIS

Litigation

On October 2, 2007 the 333rd District Court of Harris County, Texas granted the defendants' motion for summary judgment in the WTG suit. It is unknown at this time whether plaintiff will seek an appeal.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of ConocoPhillips

We have audited the accompanying combined balance sheet of the Midstream Operations sold to Targa Resources, Inc. (the "Midstream Operations") as of April 15, 2004, and the related combined statements of operations, parent company investment, and cash flows for the 106-day period ended April 15, 2004. These financial statements are the responsibility of ConocoPhillips' management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Midstream Operations' internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Midstream Operations' internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the combined financial position of the Midstream Operations sold to Targa Resources, Inc. at April 15, 2004, and the combined results of its operations and its cash flows for the 106-day period ended April 15, 2004, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas
July 29, 2005

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CONOCOPHILLIPS COMPANY'S
MIDSTREAM OPERATIONS SOLD TO TARGA RESOURCES, INC.

COMBINED INCOME STATEMENT

	106-Day Period Ended April 15 2004
	(In Thousands)
Revenues	
Sales and other operating revenues	$ 232,769
Total revenues	232,769
Costs and Expenses	
Purchased products	212,306
Operating expenses	7,850
Selling, general and administrative expenses	757
Depreciation and amortization	3,833
Taxes other than income taxes	1,407
Other	—
Total Costs and Expenses	226,153
Income before income taxes	6,616
Provision for income taxes	2,567
Net Income	$ 4,049

See Notes to Combined Financial Statements.

CONOCOPHILLIPS COMPANY'S
MIDSTREAM OPERATIONS SOLD TO TARGA RESOURCES, INC.

COMBINED BALANCE SHEET

	At April 15 2004
	(In thousands)
Assets	
Cash and cash equivalents	$ —
Accounts receivable	20,985
Materials and supplies inventories	1,332
Prepaid expenses and other current assets	493
Total Current Assets	22,810
Net properties, plants and equipment	266,011
Total Assets	$ 288,821
Liabilities	
Accounts payable	$ 27,477
Accrued income and other taxes	711
Other accruals and current liabilities	991
Total Current Liabilities	29,179
Accrued environmental costs	827
Deferred income taxes	87,954
Total Liabilities	117,960
Parent Company Investment	
Parent company investment	170,861
Total	$ 288,821

See Notes to Combined Financial Statements.

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CONOCOPHILLIPS COMPANY'S
MIDSTREAM OPERATIONS SOLD TO TARGA RESOURCES, INC.

COMBINED STATEMENT OF CASH FLOWS

	106-Day Period Ended April 15 2004 (In thousands)
Cash Flows From Operating Activities	
Net income	$ 4,049
Adjustments to reconcile net income to net cash provided by operating activities	
Non-working capital adjustments	
Depreciation and amortization	3,833
Deferred taxes	(648)
Other	482
Working capital adjustments	
Decrease (increase) in accounts receivable	23,733
Decrease in inventories	—
Decrease (increase) in prepaid expenses and other current assets	1,431
Increase (decrease) in accounts payable	(21,279)
Increase (decrease) in taxes and other accruals	(121)
Net Cash Provided by Operating Activities	11,480
Cash Flows From Investing Activities	
Capital expenditures	(1,176)
Net Cash Used in Investing Activities	(1,176)
Cash Flows From Financing Activities	
Net cash changes in parent company investment	(10,304)
Net Cash Used in Financing Activities	(10,304)
Net Change in Cash and Cash Equivalents	—
Cash and cash equivalents at beginning of period	—
Cash and Cash Equivalents at End of Period	$ —

See Notes to Combined Financial Statements.

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CONOCOPHILLIPS COMPANY'S
MIDSTREAM OPERATIONS SOLD TO TARGA RESOURCES, INC.

COMBINED STATEMENT OF PARENT COMPANY INVESTMENT

	(In thousands)
Parent company investment at December 31, 2003	$ 177,264
Net income	4,049
Net change in distributions to parent company	(10,452)
Parent company investment at April 15, 2004	$ 170,861

See Notes to Combined Financial Statements.

CONOCOPHILLIPS COMPANY'S
MIDSTREAM OPERATIONS SOLD TO TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS

Note 1 — Accounting Policies

- ***Basis of Financial Statements*** — These combined financial statements represent certain natural gas liquids operations of ConocoPhillips Company (the parent company) located in South Louisiana and the Permian Basin in West Texas (hereinafter collectively referred to as the Midstream Operations), which ConocoPhillips Company sold to Targa Resources, Inc., effective April 1, 2004. These operations are integrated gathering and processing systems that purchase raw natural gas from producers, which is gathered through pipeline gathering systems. The gathered natural gas is then processed to extract natural gas liquids from the raw gas stream and the remaining "residue" gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the natural gas liquids are fractionated — separated into individual components like ethane, butane and propane — and marketed as chemical feedstock, fuel, or blendstock. These are sold to third parties, as well as to ConocoPhillips Company.

  These financial statements are presented on a going-concern basis, as if these assets had existed as an entity separate from ConocoPhillips Company during the periods presented. These assets were not a separate legal entity during the periods presented. References to the Midstream Operations are to "ConocoPhillips Company, with respect to the midstream operations that it sold to Targa." During the periods presented, ConocoPhillips Company charged the Midstream Operations a portion of its corporate support costs, including engineering, legal, treasury, planning, environmental, tax, auditing, information technology, and other corporate services, based on usage, actual costs or other allocation methods considered reasonable by ConocoPhillips Company management. Accordingly, expenses included in these financial statements may not be indicative of the level of expenses which might have been incurred had the Midstream Operations been operating as a separate stand-alone company.

  ConocoPhillips Company is a wholly owned subsidiary of ConocoPhillips, a company incorporated in the state of Delaware on November 16, 2001, in connection with, and in anticipation of, the merger between Conoco Inc. (Conoco) and Phillips Petroleum Company (Phillips). The merger between Conoco and Phillips (the merger) was consummated on August 30, 2002, and Conoco and Phillips each became wholly owned subsidiaries of ConocoPhillips. For accounting purposes, Phillips was designated as the acquirer of Conoco and ConocoPhillips was treated as the successor of Phillips. Subsequent to the merger, Phillips was renamed ConocoPhillips Company. Before the merger, the Midstream Operations were owned by Conoco. As a result of the merger and the subsequent allocation of the purchase price to specific assets and liabilities, the recorded book value of the Midstream Operations was re-measured to fair value as of August 30, 2002.

- ***Revenue Recognition*** — Revenues associated with sales of natural gas, natural gas liquids, and other items are recorded when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, which is generally at the tailgate of the processing plant. Midstream Operations uses commodity derivative instruments, such as swaps and futures, in various markets to effectively convert fixed-price contracts to a floating price. See Note 1 — Accounting Policies — Derivative Instruments, for additional information on the accounting for, and reporting of, commodity derivatives contracts.

- ***Use of Estimates*** — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from the estimates and assumptions used.

- ***Parent Company Investment*** — The parent company investment included in the balance sheet represents the net balances resulting from various transactions between the Midstream Operations and

CONOCOPHILLIPS COMPANY'S
MIDSTREAM OPERATIONS SOLD TO TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

ConocoPhillips Company. There were no terms of settlement or interest charges associated with the account balance. The balance included the Midstream Operations' participation in ConocoPhillips Company's central cash management program. The Midstream Operations' cash receipts were remitted to, and its cash disbursements were funded by, ConocoPhillips Company. Other transactions included product purchases from, and sales to, the parent company; the Midstream Operations' share of the current portion of ConocoPhillips Company's consolidated income tax liability; and other administrative and support expenses incurred by ConocoPhillips Company and allocated or charged to the Midstream Operations.

- ***Inventories*** — Materials and supplies are valued at average cost.
- ***Derivative Instruments*** — All derivative instruments are recorded on the balance sheet at fair value in either prepaid expenses and other current assets or other accruals and current liabilities. Recognition of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives that are not accounted for as hedges under Statement of Financial Accounting Standard (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," are recognized immediately in earnings. In the combined statement of operations, gains and losses from derivatives are recorded in sales and other operating revenues.
- ***Properties, Plants and Equipment*** — Properties, plants and equipment are recorded at cost except when re-measured to fair-value in a merger.
- ***Depreciation and Amortization*** — Depreciation and amortization is determined by the group-straight-line method over a 20-year to 22-year useful life. Prior to August 30, 2002, properties, plants and equipment were depreciated over a 25-year useful life.
- ***Impairment of Properties, Plants and Equipment*** — Properties, plants and equipment used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as Property Impairments in the periods in which the determination of impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell. In assessing impairment and applying the provisions of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," management considered the Midstream Operations as a going concern and separate reporting entity. Therefore, considerations related to ConocoPhillips Company's intentions to dispose of these operations are not reflected in these statements. However, as described in Note 3, ConocoPhillips Company incurred an impairment charge on its investment in the Midstream Operations.

  The expected future cash flows used for impairment reviews and related net realizable value calculations are based on production volumes, prices and costs, considering all available evidence at the date of the review.
- ***Maintenance and Repairs*** — The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred.

- ***Environmental Costs*** — Environmental expenditures are expensed or capitalized as appropriate, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that do not have future economic benefit are expensed. Liabilities for these expenditures are recorded on an undiscounted basis (unless acquired in a purchase business acquisition such as the merger) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Since the Midstream Operations were acquired by ConocoPhillips Company in the merger of Conoco and Phillips, the majority of its environmental liabilities are recorded on a discounted basis. Recoveries of environmental remediation costs from other parties, such as state reimbursement funds, are recorded as assets when their receipt is probable.

- ***Income Taxes*** — The Midstream Operations' results of operations are included in the consolidated U.S. federal and state income tax returns of ConocoPhillips. Deferred taxes are provided on all temporary differences between the financial-reporting basis and the tax basis of the Midstream Operations' assets and liabilities. Income tax expense or benefit represents Midstream Operations, on a separate-return basis, using the same principles and elections used in ConocoPhillips' consolidated return. Any resulting current tax liability or refund is settled with the parent company on a current basis.

Note 2 — Related-Party Transactions

Significant transactions with related parties were:

	106-Day Period Ended April 15 2004 (In thousands)
Sales and other operating revenues(a)	$ 112,706
Purchased products(b)	23,667
Selling, general and administrative expenses(c)	752

(a) The Midstream Operations sold natural gas and natural gas liquids to ConocoPhillips Company for re-marketing to third parties, at prices that approximate market.

(b) The Midstream Operations purchased natural gas feedstocks for its processing plants from ConocoPhillips Company, at prices that approximate market.

(c) ConocoPhillips Company charged the Midstream Operations a portion of its corporate support costs, including engineering, legal, treasury, planning, environmental, tax, auditing, information technology, research and development, and other corporate services, based on usage, actual costs, or other allocation methods considered reasonable by ConocoPhillips Company's management.

Inventory profit-or-loss-elimination amounts at April 15, 2004 on purchases from, and sales to, related parties were not material.

Note 3 — Properties, Plants and Equipment

The Midstream Operations' investment in properties, plants and equipment, with accumulated depreciation and amortization, at balance-sheet date was:

	At April 15 2004 (In thousands)
Processing plants	$ 107,308
Pipelines	178,208
Gross properties, plants and equipment	285,516
Accumulated depreciation and amortization	(19,505)
Net properties, plants and equipment	$ 266,011

Properties, plants and equipment consist primarily of processing plant and pipeline assets, which are depreciated on estimated useful lives of 20 to 22 years. At the end of August 2002, in conjunction with the merger, the Midstream Operations' properties, plants and equipment were re-measured to fair value. As part of this, the useful lives of the plants changed from 25 years to 20 years for Louisiana and to 22 years for the plants in West Texas.

In 2004, ConocoPhillips Company incurred a $24,141,000 impairment to write down to net realizable value the properties, plants and equipment planned to be sold to Targa Resources, Inc.

Note 4 — Accrued Environmental Costs and Asset Retirement Obligations

Midstream Operations had environmental costs of $1,055,207 accrued at April 15, 2004. Of the total accrued at April 15, 2004, $227,988 was classified as short-term on the combined balance sheet. Based on analyses of available information and previous experience with respect to remediation sites, it is reasonably possible that the costs associated with these sites could exceed current accruals by amounts that may not be material but that could range up to $3,000,000, in aggregate.

Because the Midstream Operations were acquired by ConocoPhillips Company in the merger of Conoco and Phillips, the majority of its environmental liabilities are recorded on a discounted basis. Expected expenditures for acquired environmental obligations are discounted using a 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $380,205 at April 15, 2004. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $69,000 in 2004, $50,000 in 2005, $30,000 in 2006, $10,000 in 2007, $10,000 in 2008, $10,000 in 2009, and $294,000 for all future years after 2009.

Effective January 1, 2003, Midstream Operations adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which applies to legal obligations associated with the retirement and removal of long-lived assets. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, an entity capitalizes the cost by increasing the carrying amount of the related properties, plants and equipment. Over time, the liability is increased for the change in its present value, and the initial capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset.

Midstream Operations facilities, such as plants and office buildings, are not presently subject to any legal requirements to remove these facilities and so are not within the scope of SFAS No. 143. Consequently, application of this new accounting standard did not result in an increase in net properties, plants and equipment or impact net income.

Note 5 — Contingencies

In the case of all known contingencies, the Midstream Operations accrue an undiscounted liability when the loss is probable and the amount is reasonably estimable. These liabilities are not reduced for potential insurance recoveries. If applicable, undiscounted receivables are accrued for probable insurance or other third-party recoveries. Based on information available at the time of the preparation of these financial statements, the management of ConocoPhillips Company believed that it was remote that future costs related to known contingent liability exposures would exceed accruals by an amount that would have a material adverse impact on the financial statements of the Midstream Operations.

As facts concerning contingencies become known, the Midstream Operations reassesses its position, both with respect to accrued liabilities and other potential exposures. Estimates that are particularly sensitive to future change include contingent liabilities recorded for environmental remediation and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the unknown magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of liability in proportion to other responsible parties. Estimated future costs related to legal matters are subject to change as events evolve, and as additional information becomes available during the administrative and litigation process.

Environmental — The Midstream Operations are subject to federal, state and local environmental laws and regulations. These may result in obligations to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various sites.

Other Legal Proceedings — The Midstream Operations are a party to a number of other legal proceedings pending in various courts or agencies for which, in some instances, no provision has been made.

Note 6 — Financial Instruments and Derivative Contracts

Derivative Instruments

Commodity Derivative Contracts — Midstream Operations operates in the U.S. natural gas and natural gas liquids markets and are exposed to fluctuations in the prices for these commodities. These fluctuations can affect revenues, as well as the cost of operating, investing, and financing activities. Generally, the Midstream Operations' policy is to remain exposed to market prices of commodity purchases and sales. Consistent with this policy, Midstream Operations uses commodity derivative instruments, with the assistance of ConocoPhillips Company's Commercial organization, to convert fixed-price sales contracts, which are often requested by natural gas consumers, to a floating market price.

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (Statement No. 133 or SFAS No. 133), requires companies to recognize all derivative instruments as either assets or liabilities on the balance sheet at fair value. Assets and liabilities resulting from derivative contracts open at each balance sheet date appear as prepaid expenses and other current assets or other accruals and current liabilities on the combined balance sheet.

The accounting for changes in fair value (i.e., gains or losses) of a derivative instrument depends on whether it meets the qualifications for, and has been designated as, a SFAS No. 133 hedge, and the type of hedge. At April 15, 2004, ConocoPhillips Company was not using SFAS No. 133 hedge accounting for commodity derivative contracts. All gains and losses, realized or unrealized, from the Midstream Operations' swaps and futures have been recognized in the combined statement of operations.

SFAS No. 133 also requires purchase and sales contracts for commodities that are readily convertible to cash (e.g., natural gas) to be recorded on the combined balance sheet as derivatives unless the contracts are for quantities expected to be used or sold over a reasonable period in the normal course of business (the normal purchases and normal sales exception), among other requirements, and ConocoPhillips Company has documented its intent to apply this exception. If the exception had not been applied, both the purchase or sales contract and the derivative contract mitigating the resulting risk will be recorded on the combined balance sheet at fair value in accordance with the preceding paragraphs.

Fair Values of Financial Instruments

The Midstream Operations used the following methods and assumptions to estimate the fair value of its financial instruments:

- ***Accounts receivable.*** The carrying amount reported on the combined balance sheet approximates fair value.
- ***Futures.*** Fair values are based on quoted market prices obtained form the New York Mercantile Exchange, the International Petroleum Exchange of London Limited, or other traded exchanges.
- ***Swaps.*** Fair value is estimated based on forward market prices and approximates the net gains and losses that would have been realized if the contracts had been closed out at balance-sheet date. When forward market prices are not available, they are estimated using the forward prices of a similar commodity with adjustments for differences in quality or location.

The Midstream Operations' financial instruments at balance sheet date were:

	Carrying Amount At April 15 2004	Fair Value At April 15 2004
	(In thousands)	
Financial assets		
Commodity derivatives	$ 452	452
Financial liabilities		
Commodity derivatives	763	763

Note 7 — Financial Instruments and Credit Risk

The Midstream Operations' financial instruments that were exposed to concentrations of credit risk consisted primarily of third-party trade receivables, which reflected a broad customer base, and over-the-counter derivative contracts, such as swaps, in which the credit risk derived from the counterparty to the transaction. ConocoPhillips Company's management closely monitored these exposures against predetermined credit limits, including the continual exposure adjustments that resulted from market movements. Individual counterparty exposure was managed within these limits, and included the use of cash-call margins when appropriate, thereby reducing the risk of significant non-performance. The Midstream Operations also used futures contracts, but futures have a negligible credit risk because they are traded on the New York Mercantile Exchange.

Note 8 — Employee Benefit Plans

The employees of the Midstream Operations were included in the various employee benefit plans of ConocoPhillips Company. These plans included retirement and savings plans, and employee and retiree medical, dental and life insurance plans, and other such benefits. For the purpose of these separate financial statements, the Midstream Operations were considered as if participating in multi-employer benefit plans. Its share of allocated parent company employee benefit plan expenses was $1,047,000 for the period ended April 15, 2004.

CONOCOPHILLIPS COMPANY'S
MIDSTREAM OPERATIONS SOLD TO TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

Note 9 — Taxes

Taxes charged (credited) to income were:

	106-Day Period Ended April 15 2004 (In thousands)
Taxes Other Than Income Taxes	
Property	$ 691
Payroll	182
Franchise	479
Other	55
	$ 1,407
Income Taxes	
Federal	
Current	$ 2,733
Deferred	(553)
State and local	
Current	482
Deferred	(95)
	$ 2,567

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets were:

	At April 15 2004 (In thousands)
Deferred Tax Liabilities	
Properties, plants and equipment	$ 93,022
Derivatives	—
Total deferred tax liabilities	93,022
Deferred Tax Assets	
Deferred state income tax	4,590
Derivatives	109
Accrued environmental costs	369
Total deferred tax assets	5,068
Net deferred tax liabilities	$ 87,954

CONOCOPHILLIPS COMPANY'S
MIDSTREAM OPERATIONS SOLD TO TARGA RESOURCES, INC.

NOTES TO COMBINED FINANCIAL STATEMENTS — (Continued)

The amounts of U.S. income before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

	106-Day Period Ended April 15 2004	106-Day Period Ended April 15 2004
United States income before income taxes	$ 6,616	100.0%
Federal statutory income tax	$ 2,316	35.0%
State income tax	251	3.8
	$ 2,567	38.8%

Note 10 — Cash Flow Information

	106-Day Period Ended April 15 2004
Non-Cash Investing and Financing Activities	
Distribution of non-cash assets to parent company	$ 148
Contribution of non-cash assets by parent company	—
Revaluation of assets in conjunction with the merger of Conoco and Phillips	—
Cash Payments	
Income taxes*	$ 3,215

* Amount paid to parent company for income taxes.

Report of Independent Registered Public Accounting Firm

To the Member of Targa Resources GP LLC:

In our opinion, the accompanying balance sheet presents fairly, in all material respects, the financial position of Targa Resources GP LLC (the "Company") at December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. This financial statement is the responsibility of the Company's management. Our responsibility is to express an opinion on this financial statement based on our audit. We conducted our audit of this statement 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 balance sheet is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet, assessing the accounting principles used and significant estimates made by management, and evaluating the overall balance sheet presentation. We believe that our audit of the balance sheet provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 30, 2007

TARGA RESOURCES GP LLC

BALANCE SHEET
December 31, 2006

ASSETS	
Current assets	
Cash	$ 980
Investment in Targa Resources Partners LP	20
Total assets	$1,000
MEMBER’S EQUITY	
Member’s equity	$1,000
Total member’s equity	$1,000

See accompanying notes to balance sheet

TARGA RESOURCES GP LLC

NOTES TO BALANCE SHEET

1. Nature of Operations

Targa Resources GP LLC ("General Partner") is a Delaware company, and a single member limited liability company, formed in October 2006, to become the general partner of Targa Resources Partners LP ("Partnership"). The General Partner is an indirect wholly-owned subsidiary of Targa Resources, Inc. (Targa). The General Partner owns a 2% general partner interest in the Partnership.

On October 23, 2006, Targa Resources, Inc. and its subsidiaries contributed $1,000 to the General Partner in exchange for a 100% ownership interest.

The General Partner has invested $20 in the Partnership. There were no other transactions involving the General Partner as of December 31, 2006.

2. Subsequent Event

On February 14, 2007, Targa Resources Partners LP closed on its initial public offering (or IPO) of common units. Targa Resources, Inc. contributed its North Texas System to the Partnership in connection with the IPO, representing $1.1 billion of its total assets of $3.5 billion resulting in the General Partner receiving a 2% general partnership ownership, incentive distribution rights and a 17.3% limited partnership interest. Additionally, Targa LP Inc. received a 19.3% limited partnership interest. We intend to acquire and construct additional midstream energy assets.

Concurrent with the IPO, Targa Resources Partners LP entered into a senior secured credit agreement (the "Credit Agreement") with a syndicate of lenders and financial institutions. The credit facility under the Credit Agreement consists of a five-year $500 million revolving credit facility, of which $294.5 million was outstanding following the closing.

TARGA RESOURCES GP LLC

UNAUDITED CONSOLIDATED BALANCE SHEET

	June 30, 2007 (In thousands)
ASSETS	
Current assets:	
Cash and cash equivalents	$ 9,361
Receivables from third parties	1,195
Receivables from affiliated companies	50,701
Assets from risk management activities	7,616
Other	483
Total current assets	69,356
Property, plant and equipment, at cost	1,139,723
Accumulated depreciation	(93,586)
Property, plant and equipment, net	1,046,137
Long-term assets from risk management activities	4,462
Other long-term assets	3,860
Total assets	$ 1,123,815
LIABILITIES AND OWNERS' EQUITY	
Current liabilities:	
Accounts payable	$ 4,252
Accrued liabilities	33,983
Current maturities of debt allocated from Parent	—
Liabilities from risk management activities	6,874
Total current liabilities	45,109
Long-term debt allocated from Parent	—
Long-term debt	294,500
Long-term liabilities from risk management activities	11,550
Other long-term liabilities	1,763
Deferred income tax liability	3,197
Non-controlling interest in Targa Resources Partners LP	747,280
Commitments and contingencies (Note 9)	
Member's equity	20,416
Total liabilities and member's equity	$ 1,123,815

See notes to unaudited consolidated balance sheet

Targa Resources GP LLC

Notes to Unaudited Consolidated Balance Sheet

Note 1 — Organization and Basis of Presentation

We are a single member Delaware limited liability company formed during October 2006 to become the general partner of Targa Resources Partners LP ("the Partnership"). We own a 2 percent general partner interest in the Partnership. However, due to the substantive control granted to us by the partnership agreement we consolidate our interest in the Partnership. Unless the context clearly indicates otherwise, references to "we," "our," and "us" include the operations of the Partnership. We are a wholly owned subsidiary of Targa Resources, Inc. ("Targa").

The Partnership closed its initial public offering ("IPO") of 19,320,000 common units (including 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units) at a price of $21.00 per unit on February 14, 2007. Proceeds from the IPO were approximately $377.6 million, net of offering costs. Concurrent with the IPO, Targa contributed its interest in Targa North Texas GP LLC and Targa North Texas LP ("TNT LP") to the Partnership. In return, we received a 2% general partnership interest and incentive distribution rights and Targa indirectly received a 36.6% limited partnership interest (11,528,231 Subordinated Units) in the Partnership. See Note 3 for information related to the distribution rights of the common and subordinated unitholders and our incentive distribution rights.

Our accompanying unaudited consolidated balance sheet includes historical cost-basis accounts of the assets of TNT LP, or the North Texas System, contributed to the Partnership by Targa in connection with the Partnership's IPO for the periods prior to February 14, 2007, the closing date of the IPO. Both the Partnership and TNT LP are considered "entities under common control" as defined under accounting principles generally accepted in the United States of America ("GAAP") and, as such, the transfer between entities of the assets and liabilities and operations has been recorded in a manner similar to that required for a pooling of interests, whereby the recorded assets and liabilities of TNT LP are carried forward to the consolidated partnership at their historical amounts.

On February 14, 2007 the Partnership borrowed $342.5 million through 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 also used to repay affiliate indebtedness that was contributed to the Partnership as part of TNT LP. See Note 6 for information related to the Partnership's credit facility.

Targa directs the business operations of the Partnership through its ownership and control of us. Targa and its affiliates' employees provide administrative support to us and operate our assets.

The unaudited consolidated balance sheet as of June 30, 2007 includes all adjustments, both normal and recurring, which are, in the opinion of management, necessary for a fair presentation of our financial position as of June 30, 2007. All significant intercompany balances and transactions have been eliminated in consolidation. Transactions between us, the Partnership and other Targa operations have been identified in the unaudited consolidated financial statements as transactions between affiliates (see Note 4).

Note 2 — Accounting Policies

Asset Retirement Obligations. We account for asset retirement obligations ("AROs") using Statement of Financial Accounting Standards ("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.

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

Balance as of December 31, 2006	$1,684
Liabilities incurred	—
Change in estimate	—
Accretion expense	79
Balance as of June 30, 2007	$1,763

Cash and Cash Equivalents. 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. 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.

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.

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

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

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. We are not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of Targa. 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. Accordingly, we have estimated our liability for this tax and it is presently recorded as a deferred tax liability.

Targa Resources GP LLC

Notes to Unaudited Consolidated Balance Sheet — (Continued)

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 at June 30, 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 U.S. 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 June 30, 2007.

Inventory Imbalance. Quantities of natural gas and/or natural gas liquids ("NGL") 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 NGL. 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.

Price Risk Management (Hedging). We account 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.

Our 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, we assess whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Hedge effectiveness is measured on a quarterly basis. Any ineffective portion of the unrealized gain or loss is reclassified to earnings in the current period.

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

Asset Group	Range of Years
Natural gas gathering systems and processing facilities	15 to 25
Office and miscellaneous equipment	3 to 7

Targa Resources GP LLC

Notes to Unaudited Consolidated Balance Sheet — (Continued)

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

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

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

For processing services, we 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 are paid for services by keeping a percentage of the NGL extracted and the residue gas resulting from processing natural gas. In percent-of-proceeds arrangements, we remit either a percentage of the proceeds received from the sales of residue gas and NGL or a percentage of the residue gas or NGL at the tailgate of the plant to the producer. Under the terms of percent-of-proceeds and similar contracts, we may purchase the producer's share of the processed commodities for resale or deliver the commodities to the producer at the tailgate of the plant. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, we keep the NGL extracted and returns to the producer volumes of residue gas containing an equivalent Btu content as the unprocessed natural gas that was delivered to us. Natural gas or NGL that we receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above. Under fee-based contracts, we receives a fee based on throughput volumes.

We generally report 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, we act as the principal in the transactions where we receive commodities, take title to the natural gas and NGL, and incur the risks and rewards of ownership.

Segment Information. SFAS 131, "*Disclosures about Segments of an Enterprise and Related Information*," establishes standards for reporting information about operating segments. We operate in one segment only, the natural gas gathering and processing segment.

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 157, *"Fair Value Measurements."* SFAS 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. SFAS 157 applies under other accounting pronouncements that require or permit fair value measurements, the FASB having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, SFAS 157 does not require any new fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. We have not yet determined the impact this new accounting standard will have on our 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.

Note 3 — Partnership Equity and Distributions

General. The partnership agreement requires that, within 45 days after the end of each quarter, the Partnership distribute all of its Available Cash (defined below) to unitholders of record on the applicable record date, as determined by us.

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 us 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. We are initially entitled to 2% of all quarterly distributions that the Partnership makes prior to its liquidation. Our interest is represented by 629,555 general partner units. We have the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain our current general partner interest. Our initial 2% interest in these distributions will be reduced if the Partnership issues additional units in the future and we do not contribute a proportionate amount of capital to the Partnership to maintain our 2% general partner interest.

The incentive distribution rights entitle us to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. Our incentive distribution rights are not reduced if the Partnership issues additional units in the future and we do not contribute a proportionate amount of capital to maintain our 2% general partner interest. Please read the Distributions of Available Cash during the Subordination Period and Distributions of Available Cash after the Subordination Period sections below for more details about the distribution targets and their impact on our 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 our initial 2% ownership percentage, the partnership agreement requires that the Partnership 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, and 2% to us, pro rata, until the Partnership distributes for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second,* 98% to the common unitholders, and 2% to us, pro rata, until the Partnership distributes 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, and 2% to us, pro rata, until the Partnership distributes for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth,* 98% to all unitholders, and 2% to us, pro rata, until each unitholder receives a total of $0.3881 per unit for that quarter (the First Target Distribution);
- *fifth,* 85% to all unitholders, and 15% to us, 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, and 25% to us, 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, and 50% to us pro rata, (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period. The partnership agreement requires that the Partnership make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- *first, 98% to all unitholders, and 2% to us, pro rata, until each unitholder receives a total of $0.3881 per unit for that quarter;*
- *second, 85% to all unitholders, and 15% to us, pro rata, until each unitholder receives a total of $0.4219 per unit for that quarter;*
- *third, 75% to all unitholders, and 25% to us, pro rata, until each unitholder receives a total of $0.50625 per unit for that quarter; and*
- *thereafter,* 50% to all unitholders, and 50% to us, pro rata.

Note 4 — Related-Party Transactions

Targa Resources, Inc.

On February 14, 2007, we entered into an Omnibus Agreement with Targa, the Partnership and others that addressed the reimbursement to us for costs incurred on the Partnership’s behalf and indemnification matters. Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions described in Note 7, are terminable by Targa at its option if we are removed without cause and units held by

Targa Resources GP LLC

Notes to Unaudited Consolidated Balance Sheet — (Continued)

us and our 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 the Partnership.

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 assets contributed to the Partnership in connection with its IPO. Specifically, 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, we will determine the general and administrative expenses to be allocated to the Partnership in accordance with the partnership agreement; and
- operations and certain direct expenses, which are not subject to the $5 million cap for general and administrative expenses.

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.

Sales to and purchases from affiliates. We routinely conducts business with other subsidiaries of Targa. The related transactions result primarily from purchases and sales of natural gas and NGL. Prior to February 14, 2007, all of our 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, these transactions are settled monthly in cash.

NGL and Condensate Purchase Agreement. In connection with the Partnership's IPO which closed on February 14, 2007, we entered into an NGL and high pressure condensate purchase agreement with Targa Liquids Marketing and Trade ("TLMT") 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 NGL (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.

Natural Gas Purchase Agreement. In connection with the Partnership's IPO which closed on February 14, 2007, we entered into a natural gas purchase agreement with Targa Gas Marketing LLC ("TGM") at a price based on TGM's sale price for such natural gas, less TGM's costs and expenses associated therewith. This agreement 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. Furthermore, either party may elect to terminate the agreement if either party ceases to be an affiliate of Targa.

Allocation of costs. The employees supporting our operations are employees of Targa. Our financial statements include costs allocated to us by Targa for centralized general and administrative services performed by Targa, as well as depreciation of assets utilized by Targa's centralized general and administrative functions.

Targa Resources GP LLC

Notes to Unaudited Consolidated Balance Sheet — (Continued)

Costs allocated to us were based on identification of Targa's resources which directly benefit us and our proportionate share of costs based on our estimated usage of shared resources and functions. All of the allocations are based on assumptions that management believes are reasonable; however, these allocations are not necessarily indicative of the costs and expenses that would have resulted if we had been operated as a stand-alone entity. Prior to February 14, 2007, these allocations were not settled in cash, but were settled through an adjustment to partners' capital accounts. Effective February 14, 2007, all intercompany accounts are settled monthly in cash.

Allocations of long-term debt, debt issue costs, interest rate swaps and interest expense. Prior to January 1, 2007, our financial statements included long-term debt, debt issue costs, interest rate swaps and interest expense allocated from Targa. The allocations were calculated in a manner similar to Targa's purchase price allocation related to its acquisition of Dynegy Midstream Services, Limited Partnership (the "DMS Acquisition") 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. On January 1, 2007, the allocated debt, debt issue costs and interest rate swaps were settled through a deemed partner contribution of $846.3 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 us. 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 June 30, 2007:

Period	Commodity	Instrument Type	Daily Volumes	Average Price	Index
Jul 2007 — Dec 2007	Natural gas	Swap	4,200 MMBtu	$ 9.14 per MMBtu	IF-Waha
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
Jul 2007 — Dec 2007	NGL	Swap	500 Bbl	37.80 per Bbl	OPIS-MB
Jan 2008 — Dec 2008	NGL	Swap	375 Bbl	36.75 per Bbl	OPIS-MB
Jan 2009 — Dec 2009	NGL	Swap	300 Bbl	35.39 per Bbl	OPIS-MB
Jul 2007 — Dec 2007	Condensate	Swap	319 Bbl	75.27 per Bbl	NY-WTI
Jan 2008 — Dec 2008	Condensate	Swap	264 Bbl	72.66 per Bbl	NY-WTI
Jan 2009 — Dec 2009	Condensate	Swap	202 Bbl	70.60 per Bbl	NY-WTI
Jan 2010 — Dec 2010	Condensate	Swap	181 Bbl	69.28 per Bbl	NY-WTI

Note 5 — Debt

On February 14, 2007, the Partnership 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 our option, at the higher of the lender's prime rate or the federal funds rate plus 0.5%, plus an applicable margin ranging from 0% to 1.25% dependent on 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

Targa Resources GP LLC

Notes to Unaudited Consolidated Balance Sheet — (Continued)

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 the Partnership's IPO, the guarantee of indebtedness from the entity holding the North Texas System was terminated, the collateral interest was released and the remaining affiliate indebtedness was retired and treated as a capital contribution to the Partnership. the Partnership's credit facility is secured by substantially all of its assets. the Partnership's weighted average interest rate on outstanding borrowings under its credit facility for the period from February 14, 2007 to June 30, 2007 was 6.9%.

The credit agreement restricts the Partnership's ability to make distributions of available cash to unitholders if it is in any default or an event of default (as defined in the credit agreement) exists. The credit agreement requires the Partnership's to maintain a leverage ratio (the ratio of consolidated indebtedness to our consolidated EBITDA, as defined in the credit agreement) of no more than 5.75 to 1.00, as of June 30, 2007; and 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 the Partnership's to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to its 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, the Partnership's 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 June 30, 2007, the Partnership had approximately $205.5 million available under its revolving credit facility, after giving effect to its outstanding borrowings.

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Note 6 — Derivative Instruments and Hedging Activities

At June 30, 2007, we had the following hedge arrangements for the six months ended December 31, 2007 and the years ended December 31, 2008 thru 2012:

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per day 2007	2008	2009	2010	2011	2012	Fair Value (in thousands)
Swap	IF-NGPL MC	$8.56	8,152	—	—	—	—	—	$ 2,975
Swap	IF-NGPL MC	8.43	—	6,964	—	—	—	—	2,644
Swap	IF-NGPL MC	8.02	—	—	6,256	—	—	—	340
Swap	IF-NGPL MC	7.43	—	—	—	5,685	—	—	(713)
Swap	IF-NGPL MC	7.34	—	—	—	—	2,750	—	(181)
Swap	IF-NGPL MC	7.18	—	—	—	—	—	2,750	(90)
			8,152	6,964	6,256	5,685	2,750	2,750	4,975
Swap	IF-Waha	8.73	5,460	—	—	—	—	—	1,836
Swap	IF-Waha	8.53	—	4,657	—	—	—	—	1,102
Swap	IF-Waha	7.96	—	—	4,196	—	—	—	(177)
Swap	IF-Waha	7.38	—	—	—	3,809	—	—	(659)
Swap	IF-Waha	7.36	—	—	—	—	2,250	—	(200)
Swap	IF-Waha	7.18	—	—	—	—	—	2,250	(136)
			5,460	4,657	4,196	3,809	2,250	2,250	1,766
Total Swaps			13,612	11,621	10,452	9,494	5,000	5,000	6,741
Floor	IF-NGPL MC	6.45	520	—	—	—	—	—	56
Floor	IF-NGPL MC	6.55	—	1,000	—	—	—	—	259
Floor	IF-NGPL MC	6.55	—	—	850	—	—	—	186
			520	1,000	850	—	—	—	501
Floor	IF-Waha	6.70	350	—	—	—	—	—	37
Floor	IF-Waha	6.85	—	670	—	—	—	—	168
Floor	IF-Waha	6.55	—	—	565	—	—	—	113
			350	670	565	—	—	—	318
Total Floors			870	1,670	1,415	—	—	—	819
									$ 7,560

Targa Resources GP LLC

Notes to Unaudited Consolidated Balance Sheet — (Continued)

NGL

Instrument Type	Index	Avg. Price $/gal	Barrels per day 2007	2008	2009	2010	2011	2012	Fair Value (in thousands)
Swap	OPIS-MB	$0.96	3,416	—	—	—	—	—	$ (3,375)
Swap	OPIS-MB	0.93	—	2,910	—	—	—	—	(5,136)
Swap	OPIS-MB	0.89	—	—	2,548	—	—	—	(2,863)
Swap	OPIS-MB	0.87	—	—	—	2,159	—	—	(1,718)
Swap	OPIS-MB	0.90	—	—	—	—	1,250	—	(262)
Swap	OPIS-MB	0.90	—	—	—	—	—	750	69
			3,416	2,910	2,548	2,159	1,250	750	$ (13,285)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per day 2007	2008	2009	2010	2011	2012	Fair Value (in thousands)
Swap	NY-WTI	$72.82	439	—	—	—	—	—	$ 126
Swap	NY-WTI	70.68	—	384	—	—	—	—	(223)
Swap	NY-WTI	69.00	—	—	322	—	—	—	(356)
Swap	NY-WTI	68.10	—	—	—	301	—	—	(274)
Total Swaps			439	384	322	301	—	—	(727)
Floor	NY-WTI	58.60	25	—	—	—	—	—	2
Floor	NY-WTI	60.50	—	55	—	—	—	—	48
Floor	NY-WTI	60.00	—	—	50	—	—	—	56
Total Floors			25	55	50	—	—	—	106
			464	439	372	301	—	—	$ (621)

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 revenues on the hedged volumes than we would receive in the absence of hedges.

Note 7 — Commitments and Contingencies

Environmental

For environmental matters, we record 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 the Partnership's IPO.

Our environmental liability was $0.3 million at June 30, 2007, primarily for ground water assessment and remediation.

Targa Resources GP LLC

Notes to Unaudited Consolidated Balance Sheet — (Continued)

Under the Omnibus Agreement described in Note 4, 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 Summary

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of its business. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of its business which are not expected to have a material adverse effect upon our future financial position, results of operations or cash flows.

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 4.

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 8 — Employees and Equity Compensation Plans

We do not directly employ any of the persons responsible for managing our business, nor do we have a compensation committee. Any compensation decisions that are required to be made are made by our board of directors. All of our executive officers are employees of Targa Resources LLC, a wholly-owned subsidiary of Targa. All of the outstanding equity of Targa is held indirectly by Targa Resources Investments Inc. ("Targa Investments"). Our reimbursement for the compensation of executive officers is 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 Omnibus Agreement.

Equity Compensation Plans.

We have adopted a long-term incentive plan ("LTIP") for employees, consultants and directors of our affiliates who perform services for us, including officers, directors and employees of Targa. The LTIP provides for the grant of restricted units, phantom units, unit options and substitute awards, and with respect to unit options and phantom units, the grant of distribution equivalent rights ("DERs"). Under the LTIP, up to 1.68 million common units may be delivered pursuant to awards under the LTIP. The LTIP is administered by our board of directors, and may be delegated to the compensation committee of our board of directors if one is established. Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to cash distributions paid on an outstanding common unit. Upon vesting, certain of the awards may be settled in common units or equivalent cash at the election of our general partner. For the three and six months ended June 30, 2007, we recognized compensation expense of approximately $85,000 and $115,000 related to the LTIP, respectively.

In connection with the Partnership's IPO in February 2007, we made equity-based awards to each of our non-management and independent directors under our LTIP. We also made equity-based awards to each of the non-management and independent directors of Targa Investments. The awards were determined by Targa Investments and were ratified by the board of directors of our general partner. Each of our independent and non-management directors and the independent and non-management directors of Targa Investments received an initial award of 2,000 restricted units, for a total of 16,000 restricted units. The awards to these independent and non-management directors consist of restricted units and will settle with the delivery of common units. All of these awards are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant. For the three months ended June 30, 2007 and for the period from commencement of Partnership operations (February 14, 2007) through June 30, 2007, we recognized compensation expense of approximately $60,000 and $76,000 related to the equity-based awards, respectively. We estimate that the remaining fair value of $0.3 million will be recognized in expense over the next 32 months.

Note 9 — Subsequent Event

On July 23, 2007, we approved a quarterly distribution of available cash of $0.3375 per unit (approximately $10.6 million), for the quarter ended June 30, 2007, payable on August 14, 2007 to the Partnership's unitholders of record as of the close of business on August 2, 2007.

APPENDIX A

GLOSSARY OF SELECTED TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this prospectus.

Adjusted operating surplus. For any period, operating surplus generated during that period is adjusted to:

(a) increase operating surplus by any net decreases made in subsequent periods in cash reserves for operating expenditures initially established with respect to such period to the extent such decrease results in a reduction in adjusted operating surplus in subsequent periods pursuant to clause (b) below;

(b) decrease operating surplus by any net decrease in cash reserves for operating expenditures during that period not relating to an operating expenditure made during that period; and

(c) increase operating surplus by any net increase in cash reserves for operating expenditures during that period required by any debt instrument for the repayment of principal, interest or premium.

Adjusted operating surplus does not include the portion of operating surplus described in subpart (a)(2) of the definition of "operating surplus" in this Appendix B.

Available cash. For any quarter ending prior to liquidation:

(a) all cash and cash equivalents of Targa Resources Partners LP and its subsidiaries on hand on the date of determination of available cash for that quarter;

(b) less the amount of cash reserves established by our general partner to:

(1) provide for the proper conduct of the business of Targa Resources Partners LP its subsidiaries (including reserves for future capital expenditures and for future credit needs of Targa Resource Partners LP and its subsidiaries) after that quarter;

(2) comply with applicable law or any debt instrument or other agreement or obligation to which Targa Resources Partners LP or any of its subsidiaries is a party or its assets are subject; and

(3) provide funds for minimum quarterly distributions and cumulative common unit arrearages for any one or more of the next four quarters;

provided, however, that our general partner may not establish cash reserves pursuant to clause (b)(3) immediately above unless our general partner has determined that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative common unit arrearages thereon for that quarter; and provided, further, that disbursements made by us or any of our subsidiaries or cash reserves established, increased or reduced after the end of that quarter but on or before the date of determination of available cash for that quarter shall be deemed to have been made, established, increased or reduced, for purposes of determining available cash, within that quarter if our general partner so determines.

Bbl or barrel. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil as NGLs or other liquid hydrocarbons.

BBtu. One billion Btus.

Bcf. One billion cubic feet of natural gas.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Capital account. The capital account maintained for a partner under the partnership agreement. The capital account of a partner for a common unit, a Class B unit, a subordinated unit, an incentive distribution right or any other partnership interest will be the amount which that capital account would be if that common unit, a Class B unit, subordinated unit, incentive distribution right or other partnership interest were the only interest in Targa Resources Partners LP held by a partner.

Capital surplus. All available cash distributed by us on any date from any source will be treated as distributed from operating surplus until the sum of all available cash distributed since the closing of the initial public offering equals the operating surplus from the closing of the initial public offering through the end of the quarter immediately preceding that distribution. Any excess available cash distributed by us on that date will be deemed to be capital surplus.

Closing price. The last sale price on a day, regular way, or in case no sale takes place on that day, the average of the closing bid and asked prices on that day, regular way, in either case, as reported in the principal consolidated transaction reporting system for securities listed or admitted to trading on the principal national securities exchange on which the units of that class are listed or admitted to trading. If the units of that class are not listed or admitted to trading on any national securities exchange, the last quoted price on that day. If no quoted price exists, the average of the high bid and low asked prices on that day in the over-the-counter market, as reported by the New York Stock Exchange or any other system then in use. If on any day the units of that class are not quoted by any organization of that type, the average of the closing bid and asked prices on that day as furnished by a professional market maker making a market in the units of the class selected by the our board of directors. If on that day no market maker is making a market in the units of that class, the fair value of the units on that day as determined reasonably and in good faith by our board of directors.

Condensate. A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Cumulative common unit arrearage. The amount by which the minimum quarterly distribution for a quarter during the subordination period exceeds the distribution of available cash from operating surplus actually made for that quarter on a common unit, cumulative for that quarter and all prior quarters during the subordination period.

Current market price. For any class of units listed or admitted to trading on any national securities exchange as of any date, the average of the daily closing prices for the 20 consecutive trading days immediately prior to that date.

Interim capital transactions. The following transactions if they occur prior to liquidation:

(a) borrowings, refinancings or refundings of indebtedness and sales of debt securities (other than for items purchased on open account in the ordinary course of business) by Targa Resources Partners LP or any of its subsidiaries;

(b) sales of equity interests by Targa Resources Partners LP or any of its subsidiaries;

(c) sales or other voluntary or involuntary dispositions of any assets of Targa Resources Partners LP or any of its subsidiaries (other than sales or other dispositions of inventory, accounts receivable and other assets in the ordinary course of business, and sales or other dispositions of assets as a part of normal retirements or replacements);

(d) capital contributions received; and

(e) corporate reorganizations or restructurings.

Dehydration. The process of removing liquids and moisture content from gas or other matter.

DOT. Department of Transportation.

EIA. Energy Information Administration.

EPA. Environmental Protection Agency.

Equity volumes. The portion of natural gas and/or NGLs we receive as payment for services in our gathering and processing business under percent-of-proceeds, percent-of-value or percent-of-liquids arrangements.

FERC. Federal Energy Regulatory Commission.

Field. The general area encompassed by one or more oil or gas reservoirs or pools that are located on a single geologic feature, that are otherwise closely related to the same geologic feature (either structural or stratigraphic).

Formation. A subsurface rock formation containing one or more individual and separate natural accumulations of moveable petroleum that is confined by impermeable rock and is characterized by a single-pressure system.

Fractionation. The process by which a mixed stream of natural gas liquids is separated into its constituent products.

Henry Hub. A pipeline interchange near Erath, Louisiana, where a number of interstate and intrastate pipelines interconnect through a header system operated by Sabine Pipe Line. It is the standard delivery point for the NYMEX natural gas futures contract in the U.S.

Hydrocarbon. An organic compound containing only carbon and hydrogen.

Liquefied Natural Gas (LNG). Natural gas that has been cooled to -259 degrees Fahrenheit (-161 degrees Celsius) and at which point it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

MBbl. One thousand stock tank barrels.

Mcf. One thousand cubic feet of natural gas.

MMBbl. One million stock tank barrels.

MMBtu. One million Btu.

MMcf. One million cubic feet of natural gas.

MMS. U.S. Minerals Management Service.

Natural gas. Hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

NGA. Natural Gas Act of 1938.

NGLs. Natural gas liquids. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NGPA. Natural Gas Policy Act of 1978.

NGPSA. Natural Gas Transmission Pipeline Siting Act.

NYMEX. New York Mercantile Exchange.

OCS. Outer Continental Shelf.

Operating expenditures. All of our expenditures and expenditures of our subsidiaries, including, but not limited to, taxes, reimbursements of our general partner, non-pro rata repurchase of units (other than those made with the proceeds of an Interim Capital Transaction), interest payments and maintenance capital expenditures, subject to the following:

(a) Payments (including prepayments) of principal of and premium on indebtedness will not constitute operating expenditures.

(b) Operating expenditures will not include:

(1) expansion capital expenditures;

(2) payment of transaction expenses (including taxes) relating to interim capital transactions; or

(3) distributions to unitholders.

Where capital expenditures consist of both maintenance capital expenditures and expansion capital expenditures, the general partner, with the concurrence of the conflicts committee, shall determine the allocation between the amounts paid for each.

Operating surplus. For any period prior to liquidation, on a cumulative basis and without duplication:

(a) the sum of:

(1) all cash receipts of Targa Resource Partners LP and our subsidiaries for the period beginning on the closing date of our initial public offering and ending with the last day of that period, other than cash receipts from interim capital transactions (provided that cash receipts from the termination of a commodity hedge or interest rate swap prior to its specified termination date shall be included in operating surplus in equal quarterly installments over the scheduled life of such commodity hedge or interest rate swap); and

(2) an amount equal to four times the amount needed for any one quarter for us to pay a distribution on all units (including general partner units) and incentive distribution rights at the same per-unit amount as was distributed in the immediately preceding quarter; less

(b) the sum of:

(1) operating expenditures for the period beginning on the closing date of our initial public offering and ending with the last day of that period; and

(2) the amount of cash reserves that is established by our general partner to provide funds for future operating expenditures; provided however, that disbursements made (including contributions to Targa Resource Partners LP or our subsidiaries or disbursements on behalf of Targa Resource Partners LP or our subsidiaries) or cash reserves established, increased or reduced after the end of that period but on or before the date of determination of available cash for that period shall be deemed to have been made, established, increased or reduced for purposes of determining operating surplus, within that period if our general partner so determines.

Petrochemicals. Chemicals derived from petroleum; feedstocks for the manufacture of plastics and synthetic rubber. Petrochemicals include benzene, toluene, xylene, styrene, and methanol.

Raw NGL mix. Mixed stream of NGLs, including ethane, propane, butane and natural gasolines, prior to separation in a fractionator.

Residue gas. The pipeline quality natural gas remaining after natural gas is processed.

Subordination period. The subordination period will extend from the closing of the initial public offering until the first to occur of:

(a) the first day of any quarter beginning after March 31, 2010 for which:

(1) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equaled or exceeded the sum of the minimum quarterly distributions on all of the outstanding common units and subordinated units for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date, provided, however, subordinated units may additionally convert into common units as described in “Our Cash Distribution Policy — Subordination Period — Early Conversion of Subordinated Units.”

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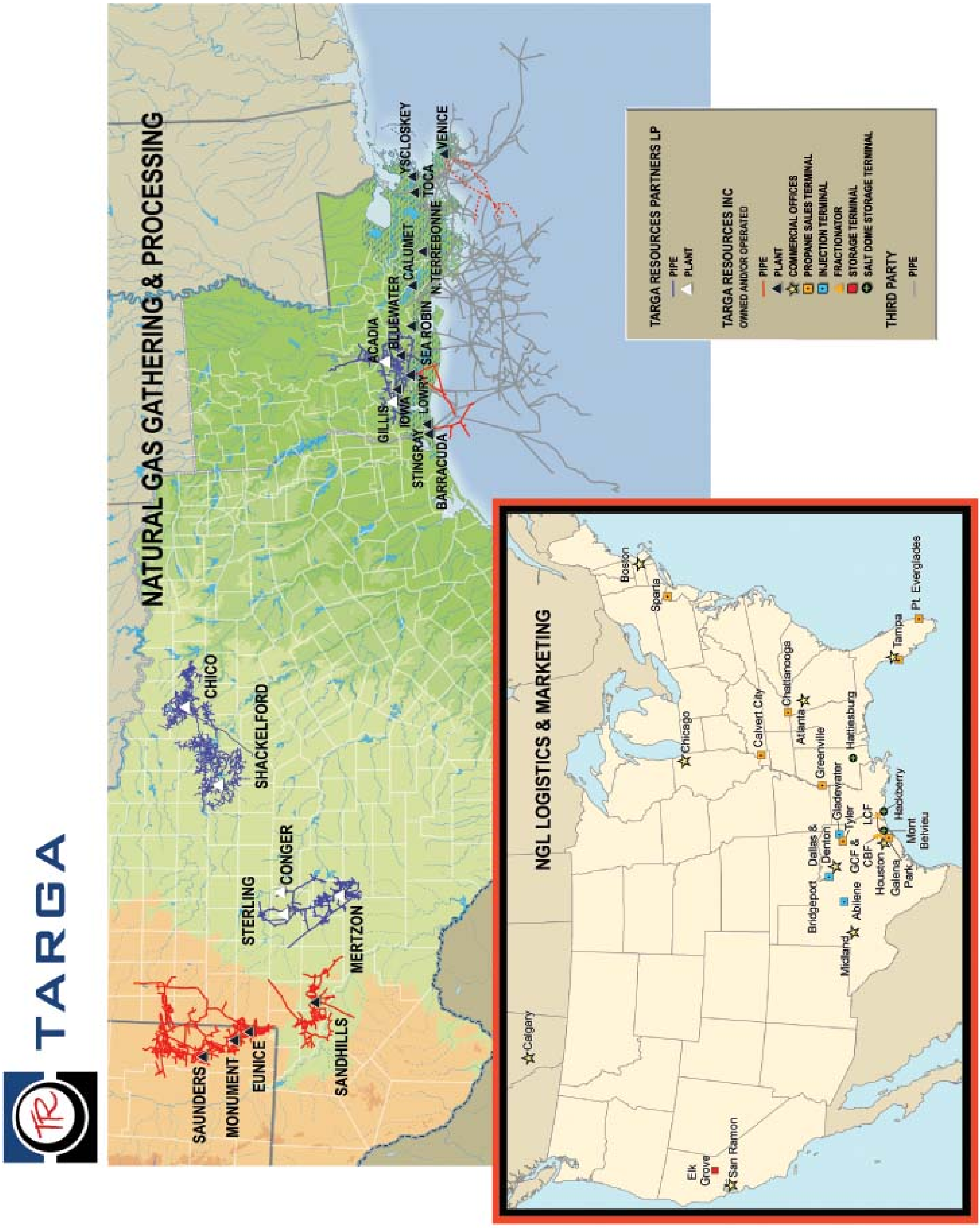

13,500,000 Common Units

Representing Limited Partner Interests

Targa Resources Partners LP

PROSPECTUS

October 18, 2007

Citi
Lehman Brothers
Goldman, Sachs & Co.
Merrill Lynch & Co.
UBS Investment Bank
Wachovia Securities
Credit Suisse
Deutsche Bank Securities
Raymond James
RBC Capital Markets
Sanders Morris Harris