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

Form 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended September 30, 2007

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number 001-33303

TARGA RESOURCES PARTNERS LP

(Exact name of registrant as specified in its charter)

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

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

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

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

Large accelerated filer o Accelerated filer o Non-accelerated filer ☑

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

There were 32,836,000 Common Units, 11,528,231 Subordinated Units and 905,066 General Partner Units outstanding as of November 1, 2007.

PART I — FINANCIAL INFORMATION

Item 1.	Unaudited Consolidated Financial Statements	4
	Consolidated Balance Sheets at September 30, 2007 and December 31, 2006	4
	Consolidated Statements of Operations for the three and nine months ended September 30, 2007 and 2006	5
	Consolidated Statements of Comprehensive Income (Loss) for the three and nine months ended September 30, 2007 and 2006	6
	Consolidated Statement of Changes in Partners' Capital for the nine months ended September 30, 2007	7
	Consolidated Statements of Cash Flows for the nine months ended September 30, 2007 and 2006	8
	Notes to Consolidated Financial Statements	9
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	28
Item 3.	Quantitative and Qualitative Disclosures about Market Risk	42
Item 4.	Controls and Procedures	44

PART II — OTHER INFORMATION

Item 1.	Legal Proceedings	45
Item 1A.	Risk Factors	45
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	65
Item 3.	Defaults Upon Senior Securities	65
Item 4.	Submission of Matters to a Vote of Security Holders	65
Item 5.	Other Information	65
Item 6.	Exhibits	65
SIGNATURES		67

Certification of CEO Pursuant to Section 302
Certification of CFO Pursuant to Section 302
Certification of CEO Pursuant to Section 906
Certification of CFO Pursuant to Section 906

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

BBtu	Billion British thermal units
Btu	British thermal unit, a measure of heating value
/d	Per day
gal	Gallons
Bbl	Barrels
MBbl	Thousand barrels
Mcf	Thousand cubic feet
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)

Price Index Definitions	
IF-NGPL MC	Inside FERC Gas Market Report, Natural Gas Pipeline, Mid-Continent
IF-Waha	Inside FERC Gas Market Report, West Texas Waha
MB-OPIS	Oil Price Information Service, Mont Belvieu, Texas
NY-WTI	NYMEX, West Texas Intermediate Crude Oil

Cautionary Statement About Forward-Looking Statements

This Quarterly Report contains “forward-looking statements” as defined in Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact, included in this Quarterly Report are forward-looking statements. Forward-looking statements include, without limitation, statements regarding our future financial position, business strategy, future capital and other expenditures, plans and objectives of management for future operations. You can typically identify forward-looking statements by the use of forward-looking words such as “may,” “potential,” “project,” “plan,” “believe,” “expect,” “anticipate,” “intend,” “estimate” or similar expressions or variations on such expressions. Each forward-looking statement reflects our current view of future events and is subject to risks, uncertainties and other factors, known and unknown, which could cause our actual results to differ materially from any results expressed or implied by our forward-looking statements. These risks and uncertainties, many of which are beyond our control, include, but are not limited to:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- our success in risk management activities, including the use of derivative financial instruments to hedge commodity and interest rate risks;
- the level of creditworthiness of counterparties to transactions;
- the amount of collateral required to be posted from time to time in our transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment or the gathering and processing industry;
- the timing and extent of changes in natural gas, NGL and commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;

- our ability to grow through acquisitions or internal growth projects, and the successful integration and future performance of such assets;
- the level and success of natural gas drilling around our assets, and our success in connecting natural gas supplies to our gathering and processing systems;
- general economic, market and business conditions; and
- the risks described elsewhere in this quarterly report.

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

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

PART I — FINANCIAL INFORMATION

Item 1. ***Consolidated Financial Statements***

TARGA RESOURCES PARTNERS LP

CONSOLIDATED BALANCE SHEETS

	September 30, 2007	December 31, 2006
	(Unaudited) (In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 28,441	$ —
Receivables from third parties	208	1,310
Receivables from affiliated companies	32,437	—
Inventory	919	—
Assets from risk management activities	8,312	17,250
Other	373	—
Total current assets	70,690	18,560
Property, plant and equipment, at cost	1,146,566	1,129,210
Accumulated depreciation	(107,981)	(65,102)
Property, plant and equipment, net	1,038,585	1,064,108
Long-term assets from risk management activities	5,755	15,541
Other long-term assets	5,572	17,612
Total assets	$ 1,120,602	$ 1,115,821
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 2,392	$ 2,789
Accrued liabilities	37,015	28,832
Current maturities of debt allocated from Parent	—	281,083
Liabilities from risk management activities	12,540	—
Total current liabilities	51,947	312,704
Long-term debt allocated from Parent	—	582,877
Long-term debt	294,500	—
Long-term liabilities from risk management activities	10,094	96
Other long-term liabilities	1,834	1,684
Deferred income tax liability	3,529	2,844
Commitments and contingencies (Note 9)		
Partners' capital:		
Common unitholders (19,336,000 units issued and outstanding at September 30, 2007)	373,970	—
Subordinated unitholders (11,528,231 units issued and outstanding at September 30, 2007)	374,201	—
General partner (629,555 units issued and outstanding at September 30, 2007)	20,436	—
Accumulated other comprehensive income (loss)	(9,909)	30,843
Net parent investment	—	184,773
Total partners' capital	758,698	215,616
Total liabilities and partners' capital	$ 1,120,602	$ 1,115,821

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(Unaudited) (In thousands, except per unit amounts)			
Revenues from third parties	$ 6,951	$ 3,505	$ 17,335	$ 8,233
Revenues from affiliates	100,712	98,461	290,324	282,657
Total operating revenues	107,663	101,966	307,659	290,890
Costs and expenses:				
Product purchases from third parties	74,457	72,182	212,208	204,532
Product purchases from affiliates	228	270	742	670
Operating expenses, excluding DD&A	6,543	6,362	18,576	17,905
Depreciation and amortization expense	14,396	14,274	42,880	41,713
General and administrative expense	2,779	1,882	6,310	5,137
	98,403	94,970	280,716	269,957
Income from operations	9,260	6,996	26,943	20,933
Other expense:				
Interest expense, net	5,059	—	12,918	—
Interest expense from affiliates, net	—	—	9,827	—
Interest expense allocated from Parent	—	18,706	—	54,369
Income (loss) before income taxes	4,201	(11,710)	4,198	(33,436)
Deferred income tax expense	332	534	997	1,988
Net income (loss)	$ 3,869	$ (12,244)	$ 3,201	$ (35,424)
Allocation of net income (loss) for the three and nine months ended September 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 September 30, 2007	3,869		10,062	
Net income	$ 3,869		$ 3,201	
General partner interest in net income for the period from February 14, 2007 to September 30, 2007	$ 77		$ 201	
Common and subordinated unitholders' interest in net income for the period from February 14, 2007 to September 30, 2007	$ 3,792		$ 9,861	
Basic net income per common and subordinated unit	$ 0.12		$ 0.32	
Diluted net income per common and subordinated unit	$ 0.12		$ 0.32	
Basic average number of common and subordinated units outstanding	30,848		30,848	
Diluted average number of common and subordinated units outstanding	30,857		30,855	

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(Unaudited) (In thousands)			
Net income (loss)	$ 3,869	$ (12,244)	$ 3,201	$ (35,424)
Other comprehensive income (loss):				
Commodity hedges:				
Change in fair value of commodity hedges	(1,083)	20,363	(34,418)	32,370
Reclassification adjustment for settled periods	(1,070)	(343)	(6,070)	(343)
Related income taxes	—	(274)	311	(274)
Interest rate swaps:				
Change in fair value of interest rate swaps	—	(638)	(575)	921
Reclassification adjustment for settled periods	—	(182)	—	(179)
Other comprehensive income (loss)	(2,153)	18,926	(40,752)	32,495
Comprehensive income (loss)	$ 1,716	$ 6,682	$ (37,551)	$ (2,929)

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 (Loss)	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	—	—	377,455	—	—	377,455
Non-cash compensation	—	—	128	—	—	128
Other comprehensive loss	—	(40,752)	—	—	—	(40,752)
Net income attributable to the period from February 14, 2007 to September 30, 2007	—	—	6,176	3,685	201	10,062
Distributions	—	—	(9,789)	(5,835)	(319)	(15,943)
Balance at September 30, 2007	$ —	$ (9,909)	$ 373,970	$ 374,201	$ 20,436	$ 758,698

See notes to unaudited consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(Unaudited) (In thousands)	
Cash flows from operating activities		
Net income (loss)	$ 3,201	$ (35,424)
Adjustments to reconcile net income (loss) to net cash provided by operating activities Depreciation	42,880	41,713
Accretion of asset retirement obligations	118	108
Amortization of debt issue costs	507	3,864
Noncash compensation	128	—
Loss on sale of assets	2	—
Deferred income tax expense	997	1,988
Risk management activities	198	—
Changes in operating assets and liabilities:		
Accounts receivable	7,521	369
Inventory	(919)	584
Other	(2,307)	630
Accounts payable	(397)	(10)
Accrued liabilities	8,183	(2,675)
Net cash provided by operating activities	60,112	11,147
Cash flows from investing activities		
Purchases of property, plant and equipment	(17,362)	(17,769)
Other	35	32
Net cash used in investing activities	(17,327)	(17,737)
Cash flows from financing activities		
Proceeds from initial public offering	380,768	—
Costs incurred in connection with public offerings	(3,313)	—
Distributions	(15,943)	—
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)	6,590
Net cash provided by (used in) financing activities	(14,344)	6,590
Net change in cash and cash equivatents	28,441	—
Cash and cash equivalents, beginning of period	—	—
Cash and cash equivalents, end of period	$ 28,441	$ —
Supplemental cash flow information:		
Net settlement of allocated indebtedness and debt issue costs	$ 190,493	$ 256
Net contribution of affiliated receivables	38,856	—
Noncash long-term debt allocation of payments from Parent	—	3,699

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"), is a Delaware limited partnership formed in October 2006. As of September 30, 2007, we operated 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") (see Note 11 — Subsequent Events). 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 $377.5 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; 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. 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 nine month periods ended September 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 nine months ended September 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	118
Balance as of September 30, 2007	$ 1,802

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. Prior to February 14, 2007, cash distributions are deemed to have occurred through partners' capital, and are reflected as an adjustment to partners' capital. Prior to February 14, 2007, the cash accounts of the Partnership were part of Targa's centralized cash management system. After this date, the Partnership maintains its own cash management system. For the period from January 1, 2007 through February 13, 2007, deemed net capital distributions from the Partnership were $0.5 million.

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

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

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

Income Taxes. The Partnership is not subject to federal income taxes. As a result, our earnings or losses for federal income tax purposes are included in the tax returns of our individual partners. In May 2006, Texas adopted a margin tax, consisting generally of a 1% tax on the amount by which total revenues exceed cost of goods sold. 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 September 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 September 30, 2007.

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

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

EITF 03-6 requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit using the two-class method. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

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

Price Risk Management (Hedging). The Partnership accounts for derivative instruments in accordance with SFAS 133, *"Accounting for Derivative Instruments and Hedging Activities,"* as amended. Under SFAS 133, all derivative instruments not qualifying for the normal purchases and normal sales exception are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If a derivative qualifies for hedge accounting and is designated as a hedge, the effective portion of the unrealized gain or loss on the derivative is deferred in accumulated other comprehensive income ("OCI"), a component of partners' capital, and reclassified to earnings when the forecasted transaction occurs. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

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

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

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

Asset Group	Range of Years
Natural gas gathering systems and processing facilities	15 to 25
Office and miscellaneous equipment	3 to 7

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

Revenue Recognition. The Partnership's primary types of sales and service activities reported as operating revenues include:

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

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

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

The Partnership generally reports revenues gross in the consolidated statements of operations, in accordance with EITF 99-19, *"Reporting Revenue Gross as a Principal versus Net as an Agent."* Except for fee-based contracts, the Partnership acts as the principal in the transactions where we receive commodities, take title to the natural gas and NGLs, and incur the risks and rewards of ownership.

Segment Information. SFAS 131, *"Disclosures about Segments of an Enterprise and Related Information,"* establishes standards for reporting information about operating segments. The Partnership operates in one segment only, the natural gas gathering and processing segment.

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 currently entitled to approximately 2% of all quarterly distributions that we make prior to our liquidation. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions will be reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest.

The incentive distribution rights held by the general partner entitle it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The general partner's incentive distribution rights are not reduced if we issue additional units in the future and the general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Please read "Distributions of Available Cash during the Subordination Period" and "Distributions of Available Cash after the Subordination Period" below for more details about the distribution targets and their impact on the general partner's incentive distribution rights.

Subordinated Units. All of the subordinated units are held by Targa GP Inc. and Targa LP Inc. The partnership agreement provides that, during the subordination period, the common units have the right to receive distributions of Available Cash each quarter in an amount equal to $0.3375 per common unit, or the "Minimum Quarterly Distribution," plus any arrearages in the payment of the Minimum Quarterly Distribution on the common units from prior quarters, before any distributions of Available Cash may be made on the subordinated units. These units are deemed "subordinated" because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the Minimum Quarterly Distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units. The practical effect of the subordinated units is to increase the likelihood that during the subordination period there will be Available Cash to be distributed on the common units. The subordination period will end, and the subordinated units will convert to common units, on a one for one basis, when certain distribution requirements, as defined in the partnership agreement, have been met. The earliest date at which the subordination period may end is April 2008.

Distributions of Available Cash during the Subordination Period. Based on the general partner's initial 2% ownership percentage, the partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter during the subordination period in the following manner:

- *first*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *second*, 98% to the common unitholders, pro rata, and 2% to the general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the Minimum Quarterly Distribution on the common units for any prior quarters during the subordination period;
- *third*, 98% to the subordinated unitholders, pro rata, and 2% to the general partner, until we distribute for each subordinated unit an amount equal to the Minimum Quarterly Distribution for that quarter;
- *fourth*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.3881 per unit for that quarter (the First Target Distribution);
- *fifth*, 85% to all unitholders, 2% to the general partner and 13% to the holders of the Incentive Distribution Rights, pro rata, until each unitholder receives a total of $0.4219 per unit for that quarter (the Second Target Distribution);
- *sixth*, 75% to all unitholders, 2% to the general partner and 23% to the holders of the Incentive Distribution Rights, pro rata, until each unitholder receives a total of $0.50625 per unit for that quarter (the Third Target Distribution); and
- *thereafter*, 50% to all unitholders, 2% to the general partner and 48% to the holders of the Incentive Distribution Rights, pro rata, (the Fourth Target Distribution).

Distributions of Available Cash after the Subordination Period. The partnership agreement requires that we make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- *first*, 98% to all unitholders, pro rata, and 2% to the general partner, until each unitholder receives a total of $0.3881 per unit for that quarter;
- *second*, 85% to all unitholders, pro rata, 2% to the general partner and 13% to the holders of the Incentive Distribution Rights, until each unitholder receives a total of $0.4219 per unit for that quarter;
- *third*, 75% to all unitholders, pro rata, 2% to the general partner and 23% to the holders of the Incentive Distribution Rights, until each unitholder receives a total of $0.50625 per unit for that quarter; and
- *thereafter*, 50% to all unitholders, pro rata, 2% to the general partner and 48% to the holders of the Incentive Distribution Rights.

Note 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 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. 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. A distribution for the second quarter of 2007 of $0.3375 per unit was approved by the Board of Directors of our general partner on July 23, 2007. On August 14, 2007, we paid this distribution (approximately $10.6 million) to unitholders of record as of the close of business on August 2, 2007.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

The following table illustrates the Partnership's calculation of net income per limited and subordinated partner unit for the three and nine months ended September 30, 2007 (in thousands, except unit and per unit information):

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Feb. 14, 2007 to September 30, 2007	Jan. 1, 2007 to Feb. 13, 2007	Nine Months Ended September 30, 2006
Revenues from third parties	$ 6,951	$ 3,505	$ 17,335	$ 13,400	$ 3,935	$ 8,233
Revenues from affiliates	100,712	98,461	290,324	252,155	38,169	282,657
	107,663	101,966	307,659	265,555	42,104	290,890
Costs and expenses:						
Product purchases	74,685	72,452	212,950	184,255	28,695	205,202
Operating expenses, excluding DD&A	6,543	6,362	18,576	15,760	2,816	17,905
Depreciation and amortization expense	14,396	14,274	42,880	35,955	6,925	41,713
General and administrative expense	2,779	1,882	6,310	5,608	702	5,137
	98,403	94,970	280,716	241,578	39,138	269,957
Income from operations	9,260	6,996	26,943	23,977	2,966	20,933
Other expense						
Interest expense, net	5,059	—	12,918	12,918	—	—
Interest expense from affiliate, net	—	—	9,827	—	9,827	—
Interest expense allocated from Parent	—	18,706	—	—	—	54,369
Income (loss) before income taxes	4,201	(11,710)	4,198	11,059	(6,861)	(33,436)
Deferred income tax expense	332	534	997	997	—	1,988
Net income (loss)	$ 3,869	$ (12,244)	$ 3,201	$ 10,062	$ (6,861)	$ (35,424)
General partner interest in net income	$ 77		$ (6,660)	$ 201	$ (6,861)	
Net income available to common and subordinated unitholders	$ 3,792		$ 9,861	$ 9,861	$ —	
Basic net income per common and subordinated unit	$ 0.12		$ 0.32	$ 0.32		
Diluted net income per common and subordinated unit	$ 0.12		$ 0.32	$ 0.32		
Basic average number of common and subordinated units outstanding	30,848		30,848	30,848		
Restrictive equivalents	9		7	7		
Diluted average number of common and subordinated units outstanding	30,857		30,855	30,855		

The calculation of basic and diluted net income per common and subordinated unit are the same for all periods presented as distributable cash flow was greater than net income for those periods and distributions to the subordinated unitholders have been equivalent to the distribution to the common unitholders for all quarters.

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 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 (see Note 11, Subsequent Events — Omnibus Agreement); and
- operations and certain direct general and administrative 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 NGLs. Prior to February 14, 2007, all of the Partnership’s expenditures were paid through Targa, resulting in inter-company transactions. Prior to February 14, 2007, settlement of these inter-company transactions was through adjustments to partners’ capital accounts. Effective February 14, 2007, these transactions are settled monthly in cash.

NGLs and Condensate Purchase Agreement. In connection with our IPO which closed on February 14, 2007, we entered into an NGLs 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 NGLs (other than high-pressure condensate) that we own or control to TLMT and (ii) we have the right to sell to TLMT or third parties the volumes of high-pressure condensate that we own or control, in each case at a price based on the prevailing market price less transportation, fractionation and certain other fees. Furthermore, either party may elect to terminate the agreement if either party ceases to be an affiliate of Targa.

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.

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.

	Nine Months Ended September 30, 2007	Feb. 14, 2007 to September 30, 2007	Jan. 1, 2007 to Feb. 13, 2007	Nine Months Ended September 30, 2006
		(In thousands)		
Cash				
Sales to affiliates	$ (290,324)	$ (252,155)	$ (38,169)	$ (282,657)
Purchases from affiliates	742	665	77	670
Allocations of general & administrative expenses — pre IPO	702	—	702	5,137
Allocations of general & administrative expenses under Omnibus Agreement	5,608	5,608	—	—
Allocated interest	—	—	—	54,369
Affiliate interest	9,837	—	9,837	—
Receivable from affiliates to be settled in cash	32,437	32,437	—	—
Payments made by the Parent	240,479	213,445	27,034	229,071
	$ (519)	$ —	$ (519)	$ 6,590
Noncash				
Net settlement of allocated indebtedness and debt issue costs			$ 190,493	$ 256
Net contribution of affiliated receivables			38,856	—
Noncash long-term debt allocation of payments from Parent			—	3,699
			229,349	3,955
			$ 228,830	$ 10,545

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 September 30, 2007:

Period	Commodity	Instrument Type	Daily Volumes		Average Price		Index
Oct 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
Oct 2007 — Dec 2007	NGLs	Swap	500	Bbl	$ 37.80	per barrel	OPIS-MB
Jan 2008 — Dec 2008	NGLs	Swap	375	Bbl	$ 36.75	per barrel	OPIS-MB
Jan 2009 — Dec 2009	NGLs	Swap	300	Bbl	$ 35.39	per barrel	OPIS-MB
Oct 2007 — Dec 2007	Condensate	Swap	319	Bbl	$ 75.27	per barrel	NY-WTI
Jan 2008 — Dec 2008	Condensate	Swap	264	Bbl	$ 72.66	per barrel	NY-WTI
Jan 2009 — Dec 2009	Condensate	Swap	202	Bbl	$ 70.60	per barrel	NY-WTI
Jan 2010 — Dec 2010	Condensate	Swap	181	Bbl	$ 69.28	per barrel	NY-WTI

Note 6 — Debt

Pre-IPO Indebtedness. 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 $870.1 million of allocated indebtedness and corresponding levels of interest expense. The entity holding the North Texas System provided a guarantee of this indebtedness. This indebtedness was also secured by a collateral interest in both the equity of the entity holding the North Texas System as well as its assets.

On January 1, 2007, Targa contributed to us affiliated indebtedness related to the North Texas System of approximately $904.5 million (including accrued interest of $88.3 million computed at 10% per anum). 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.

Post-IPO Indebtedness. On February 14, 2007, we entered into a credit agreement which provides for a five-year $500 million revolving credit facility with a syndicate of financial institutions. The revolving credit facility bears interest at the Partnership's option, at the higher of the lender's prime rate or the federal funds rate plus 0.5%, plus an applicable margin ranging from 0% to 1.25% dependent on the Partnership's total leverage ratio, or LIBOR plus an applicable margin ranging from 1.0% to 2.25% dependent on the Partnership's total leverage ratio. The Partnership initially borrowed $342.5 million under its credit facility, and concurrently repaid $48.0 million under its credit facility with the proceeds from the 2,520,000 common units sold pursuant to the full exercise by the underwriters of their option to purchase additional common units. The net proceeds of $294.5 million from this borrowing, together with approximately $371.2 million of available cash from the IPO (after payment of offering and debt issue costs and necessary operating cash reserve balances), were used to repay approximately $665.7 million of affiliate indebtedness. In connection with our IPO, the guarantee of indebtedness from the entity holding the North Texas System was terminated,the related collateral interest was released and the remaining affiliate indebtedness was retired and treated as a capital contribution to the Partnership. Our credit facility is secured by substantially all of our assets. Our weighted average interest rate on outstanding borrowings under our credit facility for the period from February 14, 2007 to September 30, 2007 was 6.7%.

The credit agreement restricts our ability to make distributions of available cash to unitholders if we are in any default or an event of default (as defined in the credit agreement) exists. The credit agreement requires us to maintain a leverage ratio (the ratio of consolidated indebtedness to our consolidated EBITDA, as defined in the credit agreement) of no more than 5.00 to 1.00 on the last day of any fiscal quarter ending on or after September 30, 2007. The credit agreement also requires us to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, as defined in the credit agreement) of no less than 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination. In addition, the credit agreement contains various covenants that may limit, among other things, our ability to:

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

The credit facility matures on February 14, 2012, at which time all unpaid principal and interest is due.

As of September 30, 2007, we had approximately $205.2 million available under our revolving credit facility, after giving effect to our outstanding borrowings of $294.5 million and the issuance of $0.3 million of letters of credit.

Note 7 — Derivative Instruments and Hedging Activities

At September 30, 2007 and December 31, 2006, OCI included $9.9 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 nine months ended September 30, 2007, deferred net gains on commodity hedges of $1.1 million and $6.1 million were reclassified from OCI and credited to income as revenues. For the three and nine months ended September 30, 2006, deferred net gains on commodity hedge of $0.3 million and $0.3 million, respectively, were reclassified from OCI and credited to income as revenues. There were no adjustments for hedge ineffectiveness during the first nine 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 nine months ended September 30, 2006, deferred net gains on interest rate hedges of $0.2 million and $0.2 million, respectively, were reclassified from OCI to net interest expense. There were no adjustments for hedge ineffectiveness during the first nine months of 2007 or 2006.

At September 30, 2007, deferred net gains of $4.6 million on commodity hedges recorded in OCI are expected to be reclassified to earnings during the next twelve months.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

At September 30, 2007, we had the following hedge arrangements which will settle during three 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	—	—	—	—	—	$ 1,836
Swap	IF-NGPL MC	8.43	—	6,964	—	—	—	—	3,958
Swap	IF-NGPL MC	8.02	—	—	6,256	—	—	—	1,415
Swap	IF-NGPL MC	7.43	—	—	—	5,685	—	—	202
Swap	IF-NGPL MC	7.34	—	—	—	—	2,750	—	72
Swap	IF-NGPL MC	7.18	—	—	—	—	—	2,750	140
			8,152	6,964	6,256	5,685	2,750	2,750	7,623
Swap	IF-Waha	8.73	5,460	—	—	—	—	—	1,258
Swap	IF-Waha	8.53	—	4,657	—	—	—	—	2,053
Swap	IF-Waha	7.96	—	—	4,196	—	—	—	331
Swap	IF-Waha	7.38	—	—	—	3,809	—	—	(262)
Swap	IF-Waha	7.36	—	—	—	—	2,250	—	(35)
Swap	IF-Waha	7.18	—	—	—	—	—	2,250	11
			5,460	4,657	4,196	3,809	2,250	2,250	3,356
Total Swaps			13,612	11,621	10,452	9,494	5,000	5,000	10,979
Floor	IF-NGPL MC	6.45	520	—	—	—	—	—	32
Floor	IF-NGPL MC	6.55	—	1,000	—	—	—	—	267
Floor	IF-NGPL MC	6.55	—	—	850	—	—	—	205
			520	1,000	850	—	—	—	504
Floor	IF-Waha	6.70	350	—	—	—	—	—	25
Floor	IF-Waha	6.85	—	670	—	—	—	—	173
Floor	IF-Waha	6.55	—	—	565	—	—	—	115
			350	670	565	—	—	—	313
Total Floors			870	1,670	1,415	—	—	—	817
									$ 11,796

NGLs

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	—	—	—	—	—	$ (3,925)
Swap	OPIS-MB	0.93	—	2,910	—	—	—	—	(9,492)
Swap	OPIS-MB	0.89	—	—	2,548	—	—	—	(4,542)
Swap	OPIS-MB	0.87	—	—	—	2,159	—	—	(684)
Swap	OPIS-MB	0.90	—	—	—	—	1,250	—	43
Swap	OPIS-MB	0.90	—	—	—	—	—	750	107
			3,416	2,910	2,548	2,159	1,250	750	$ (18,493)

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	—	—	—	—	—	$ (268)
Swap	NY-WTI	70.68	—	384	—	—	—	—	(777)
Swap	NY-WTI	69.00	—	—	322	—	—	—	(491)
Swap	NY-WTI	68.10	—	—	—	301	—	—	(388)
Total Swaps			439	384	322	301	—	—	(1,924)
Floor	NY-WTI	$ 58.60	25	—	—	—	—	—	0
Floor	NY-WTI	60.50	—	55	—	—	—	—	17
Floor	NY-WTI	60.00	—	—	50	—	—	—	37
Total Floors			25	55	50	—	—	—	54
									$ (1,870)

The fair value of derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. These contracts may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges.

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 $1.0 million for the three and nine months ended September 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 September 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

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 (see Note 11, Subsequent Events — Litigation).

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 TR GP, 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 an equivalent cash amount at the election of our general partner. For the three and nine months ended September 30, 2007, we recognized compensation expense of approximately $56,000 and $171,000 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 September 30, 2007 and for the period from commencement of Partnership operations (February 14, 2007) through September 30, 2007, we recognized compensation expense of approximately $52,000 and $129,000 related to the equity-based awards, respectively. We estimate that the remaining fair value of $0.2 million will be recognized in expense over the next 29 months.

Note 11 — Subsequent Events

Distribution

On October 23, 2007, our general partner approved a quarterly distribution of available cash of $0.3375 per unit (approximately $15.3 million), for the quarter ended September 30, 2007, payable on November 14, 2007 to unitholders of record as of the close of business on November 4, 2007.

Underwriting Agreement

On October 18, 2007, we entered into an Underwriting Agreement (the “Underwriting Agreement”) with TR GP and the underwriters named therein (the “Underwriters”) providing for the offer and sale in a firm commitment underwritten offering of 13,500,000 common units representing limited partner interests in us at a price of $26.87 per Common Unit ($25.796 per Common Unit, net of underwriting discounts) (the “Offering”). Pursuant to the Underwriting Agreement, we granted the Underwriters a 30-day option to purchase up to an additional 2,025,000 Common Units to cover over-allotments, if any, on the same terms as those Common Units sold by us.

In the Underwriting Agreement, we agreed to indemnify the Underwriters against certain liabilities, including liabilities under the Securities Act of 1933, as amended, or to contribute to payments the Underwriters may be required to make because of any of those liabilities. The transactions contemplated by the Underwriting Agreement were consummated on October 24, 2007. Proceeds from the offering were approximately $348.2 million, net of underwriting discounts.

Acquired Businesses

On October 24, 2007, we completed the purchase from Targa of its ownership interests in Targa Texas Field Services LP, (the “SAOU” system), and Targa Louisiana Field Services LLC (the “LOU” system). This acquisition consisted of the SAOU systems’ natural gas gathering and processing businesses located in the Permian Basin of west Texas and the LOU systems’ natural gas gathering and processing businesses located in southwest Louisiana. The total value of the transaction was approximately $705 million, subject to certain post-closing adjustments. In addition, we paid approximately $24.2 million to Targa for the termination of certain hedge transactions. Total consideration paid by us to Targa consisted of cash of approximately $721.7 million and 275,511 general partner units issued to Targa to allow it to maintain its 2% general partner interest in us. Our acquisition of the SAOU and LOU systems will be accounted for under common control accounting. Under common control accounting, the SAOU and LOU systems assets and liabilities are recorded at their book value with the balance of the acquisition proceeds recorded as an adjustment to parent equity.

Supplement and Amendment of Credit Facility

Concurrent with the acquisition of the SAOU and LOU systems, we entered into a Commitment Increase Supplement (the “Supplement”) to our existing five-year $500 million senior secured revolving credit facility. The Supplement increased the aggregate commitments under the Credit Agreement by $250 million to an aggregate of $750 million. We paid for our acquisition of the SAOU and LOU systems with the proceeds from our offering of common units and borrowings under the increased senior secured revolving credit facility.

On October 24, 2007, we entered into the First Amendment to Credit Agreement (the “Amendment”). The Amendment increased by $250 million the maximum amount of increases to the aggregate commitments that may be requested by us. The Amendment allows us to request commitments under the Credit Agreement, as supplemented and amended, up to $1 billion.

Omnibus Agreement

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

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

ii. our obligation to reimburse Targa and its affiliates for the provision of general and administrative services (subject to a cap of $5 million (relating to the North Texas System) in the first year, with increases in the subsequent two years based on a formula specified in the Amended and Restated Omnibus Agreement),

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

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

With respect to the businesses acquired by us upon the closing of the acquisition of the SAOU and LOU systems, we will reimburse Targa for the following expenses:

i. general and administrative expenses, allocated to the acquired businesses according to Targa's previously established allocation practices, and

ii. operating and certain direct expenses.

Litigation

On December 8, 2005, WTG Gas Processing ("WTG") filed suit in the 333rd District Court of Harris County, Texas against several defendants, including Targa Resources, Inc. and 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. WTG's motion to reconsider and for new trial is pending before the Court. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit.

Item 2. ***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) representing limited partner interests in us 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, for necessary operating cash reserve balances 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 following discussion analyzes our financial condition and results of operations. You should read the following discussion of our financial condition and results of operations in conjunction with our consolidated financial statements and notes included elsewhere in this Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2006. The historical financial statements included in this item reflect the results of operations of the assets contributed to us by Targa in connection with our IPO (the "North Texas System"). As used in this report, unless we indicate otherwise, the terms "Partnership," "our," "we," "us" and similar terms refer to Targa Resources Partners LP, together with our subsidiaries, including Targa North Texas LP ("TNT LP"). The Partnership as used herein refers to the consolidated financial results and operations of TNT LP from its inception through its contribution to us, and to the Partnership thereafter. The term "Targa" refers to Targa Resources, Inc. and its subsidiaries and affiliates (other than us).

Overview

We are a Delaware limited partnership formed in October 2006 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. 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.

The unaudited consolidated financial statements of the Partnership include historical cost-basis accounts of TNT LP (the "North Texas System") 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. 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 recorded amounts.

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) and keep-whole contracts (representing approximately 3% of our gathered natural gas volumes), 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 Item 7A.

Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk in our Annual Report on Form 10-K for the year ended December 31, 2006.

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 NGLs prices, may change as a result of producer preferences, competition, and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common as well as other market factors. For a more complete discussion of the types of contracts under which we process natural gas, please see Item 1. Business — Midstream Industry Overview in our Annual Report on Form 10-K for the year ended December 31, 2006.

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. TNT 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 TNT 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 Item 7A. Quantitative and Qualitative Disclosures about Market Risk — Commodity Price Risk in our Annual Report on Form 10-K for the year ended December 31, 2006.

General and Administrative Expenses. The Partnership recognized general and administrative expenses as a result of allocations from the consolidated general and administrative expenses of Targa. On February 14, 2007 the Partnership entered into the Omnibus Agreement with Targa pursuant to which our allocated general and administrative expenses are capped at $5 million per year for three years, subject to adjustment. 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 Partnership. For a more complete description of the Omnibus Agreement, please see Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement in our Annual Report on Form 10-K for the year ended December 31, 2006.

Working Capital Adjustments. In the historical financial statements of the North Texas System, all intercompany transactions, including commodity sales and expense reimbursements, were not cash settled with Targa, but were recorded as an adjustment to parent equity on the balance sheet. The primary intercompany transactions between Targa and the Partnership were 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 Partnership did 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 Partnership. Subsequent to February 14, 2007, all transactions with Targa and its affiliates are cash settled on a monthly basis.

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 was paid on August 14, 2007 to unitholders of record as of the close of business on August 2, 2007. For the third 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 October 24, 2007. This distribution is payable on November 14, 2007 to unitholders of record as of the close of business on November 4, 2007.

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 three and nine months ended September 30, 2007 and 2006, 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 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, please see Item 13. Certain Relationships and Related Transactions and Director Independence and Item 1. Business — Market Access — Chico System Market Access in our Annual Report on Form 10-K for the year ended December 31, 2006.

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) EBITDA (as defined below) and (6) distributable cash flow.

Throughput Volumes, Facility Efficiencies and Fuel Consumption. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our systems. This is achieved by connecting new wells as well as by capturing supplies currently gathered by third-parties. In addition, we seek to increase operating margins by limiting volume losses and reducing fuel consumption by increasing compression efficiency. With our gathering systems' extensive use of remote monitoring capabilities, we monitor the volumes of natural gas received at the wellhead or central delivery points along our gathering systems, the volume of natural gas received at our processing plant inlets and the volumes of NGLs and residue natural gas recovered by our processing plants. This information is tracked through our processing plants to determine customer settlements and helps us increase efficiency and reduce fuel consumption.

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

Operating Margin. We review our 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 expenses. Natural gas, NGL and condensate sales revenues include 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.

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 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.

EBITDA. EBITDA is another non-GAAP financial measure that is used by us. We define EBITDA as net income before interest, income taxes, depreciation and amortization. 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 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 EBITDA are net cash provided by operating activities and net income. Our non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities and GAAP net income. EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You should not consider EBITDA in isolation or as a substitute for analysis of our results as reported under GAAP. Because 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 EBITDA may not be comparable to similarly titled measures of other companies.

Management compensates for the limitations of EBITDA 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.

Reconciliation of Non-GAAP Measures

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
		(In millions) (unaudited)		
Reconciliation of "EBITDA" to net cash provided by operating activities:				
Net cash provided by operating activities	$ 36.6	$ 7.7	$ 60.1	$ 11.1
Allocated interest expense from parent(1)	—	17.4	—	50.5
Interest expense, net(1)	4.8	—	22.2	—
Changes in operating working capital which used (provided) cash:				
Accounts receivable	(19.2)	—	(7.5)	(0.4)
Accounts payable and accrued liabilities	(1.2)	(4.1)	(7.8)	2.7
Other, including changes in noncurrent assets and liabilities	2.6	0.3	2.8	(1.2)
EBITDA	$ 23.6	$ 21.3	$ 69.8	$ 62.7
Reconciliation of "EBITDA" to net income (loss):				
Net income (loss)	$ 3.9	$ (12.2)	$ 3.2	$ (35.4)
Add:				
Allocated interest expense, net	—	18.7	—	54.4
Interest expense, net	5.0	—	22.7	—
Deferred income tax expense	0.3	0.5	1.0	2.0
Depreciation and amortization expense	14.4	14.3	42.9	41.7
EBITDA	$ 23.6	$ 21.3	$ 69.8	$ 62.7
Reconciliation of "operating margin" to net income (loss):				
Net income (loss)	$ 3.9	$ (12.2)	$ 3.2	$ (35.4)
Add:				
Depreciation and amortization expense	14.4	14.3	42.9	41.7
Deferred income tax expense	0.3	0.5	1.0	2.0
Allocated interest expense, net	—	18.7	—	54.4
Interest expense, net	5.0	—	22.7	—
General and administrative expense	2.8	1.9	6.3	5.1
Operating margin	$ 26.4	$ 23.2	$ 76.1	$ 67.8

(1) Net of amortization of debt issuance costs of $.2 million and $.5 million for the three and nine months ended September 30, 2007 and $1.3 million and $3.9 million for the three and nine months ended September 30, 2006.

Distributable Cash Flow. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by 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 comparable 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.

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
		(In millions) (Unaudited)		
Reconciliation of "Distributable cash flow" to net income (loss):				
Net income (loss)	$ 3.9	$ (12.2)	$ 3.2	$ (35.4)
Depreciation and amortization expense	14.4	14.3	42.9	41.7
Deferred income tax expense	0.3	0.5	1.0	2.0
Amortization of debt issue costs	0.2	1.3	0.5	3.9
Maintenance capital expenditures	(4.0)	(2.7)	(9.3)	(9.0)
Distributable cash flow	$ 14.8	$ 1.2	$ 38.3	$ 3.2

Critical Accounting Policies and Estimates

There have been no significant changes to our critical accounting policies and estimates since year-end. For a more complete description of our critical accounting polices and estimates, please see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates in our Annual Report on Form 10-K for the year ended December 31, 2006.

Results of Operations

The following table and discussion relate to the three and nine months ended September 30, 2007 and 2006 and is a summary of our results of operations for the periods then ended.

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions of dollars, except operating and price data)			
Revenues	$ 107.7	$ 102.0	$ 307.7	$ 290.9
Product purchases	74.7	72.4	213.0	205.2
Operating expense, excluding DD&A	6.6	6.4	18.6	17.9
Depreciation and amortization expense	14.4	14.3	42.9	41.7
General and administrative expense	2.8	1.9	6.3	5.1
Income from operations	9.2	7.0	26.9	21.0
Interest expense, net	5.0	18.7	22.7	54.4
Deferred income tax expense(1)	0.3	0.5	1.0	2.0
Net income (loss)	$ 3.9	$ (12.2)	$ 3.2	$ (35.4)
Financial data:				
Operating margin(2)	$ 26.4	$ 23.2	$ 76.1	$ 67.8
EBITDA(3)	$ 23.6	$ 21.3	$ 69.8	$ 62.7
Operating data:				
Gathering throughput, MMcf/d(4)	165.7	170.1	166.1	168.2
Plant natural gas inlet, MMcf/d(5)(6)	160.8	164.0	160.3	161.6
Gross NGL production, MBbl/d	19.2	19.1	18.0	18.8
Natural gas sales, BBtu/d(6)	75.6	76.6	75.8	75.2
NGL sales, MBbl/d	14.6	14.4	13.5	14.1
Condensate sales, MBbl/d	1.6	1.5	1.8	1.6
Natural Gas, per MMBtu				
Average realized sales price	$ 5.44	$ 5.73	$ 6.11	$ 6.09
Impact of hedging	0.49	0.12	0.42	0.04
Average realized price	$ 5.93	$ 5.85	$ 6.53	$ 6.13
NGL, per gal				
Average realized sales price	$ 1.04	$ 0.96	$ 0.94	$ 0.88
Impact of hedging	(0.04)	(0.01)	(0.02)	—
Average realized price	$ 1.00	$ 0.95	$ 0.92	$ 0.88
Condensate, per Bbl				
Average realized sales price	$ 61.64	$ 57.39	$ 53.81	$ 53.67
Impact of hedging	(0.71)	1.27	1.58	0.42
Average realized price	$ 60.93	$ 58.66	$ 55.39	$ 54.09

(1) In May 2006, Texas adopted a margin tax effective January 1, 2007, consisting of a 1% tax on the amount by which total revenues exceed 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 included in this Item 2.

(3) EBITDA is net income before interest, income taxes, depreciation and amortization. Please see Non-GAAP Financial Measures — EBITDA, included in this Item 2.

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

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

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

Comparison of Three Months Ended September 30, 2007 to Three Months Ended September 30, 2006

Our revenues increased $5.7 million, or 6%, to $107.7 million for the three months ended September 30, 2007 compared to $102.0 million for the three months ended September 30, 2006. The increase is primarily due to:

- a net increase attributable to commodity sales volume of $0.7 million, consisting of an increase in NGL and condensate revenues of $0.8 million and $0.4 million, respectively, offset by a decrease in natural gas revenues of $0.5 million.
- a net increase attributable to commodity prices of $3.9 million, consisting of increases in natural gas, NGL and condensate revenues of $0.5 million, $3.0 million and $0.4 million, respectively.
- an increase in revenues from fee based processing activities of $1.1 million.

Average realized prices for natural gas increased by $0.08 per MMBtu (including a $0.37 net increase per MMBtu related to hedging activities), or 1%, to $5.93 per MMBtu for the three months ended September 30, 2007 compared to $5.85 per MMBtu for the three months ended September 30, 2006. The average realized price for NGLs increased by $0.05 per gallon (net of a $0.03 net decrease per gallon related to hedging activities), or 5%, to $1.00 per gallon for the three months ended September 30, 2007 compared to $0.95 per gallon for the three months ended September 30, 2006. The average realized price for condensate increased by $2.27 per Bbl (including a $1.98 net decrease per Bbl related to hedging activities), or 4%, to $60.93 per Bbl for the three months ended September 30, 2007 compared to $58.66 per Bbl for the three months ended September 30, 2006.

Natural gas sales volumes decreased by 1.0 BBtu/d, to 75.6 BBtu/d for the three months ended September 30, 2007 compared to 76.6 BBtu/d for the three months ended September 30, 2006. For the three months ended September 30, 2007, a major producer started a multi-well workover program slightly reducing volumes available for processing. NGL sales volumes increased by 0.2 MBbl/d, to 14.6 MBbl/d for the three months ended September 30, 2007 compared to 14.4 MBbl/d for the three months ended September 30, 2006. Condensate sales volumes increased by 0.1 MBbl/d, to 1.6 MBbl/d for the three months ended September 30, 2007 compared to 1.5 MBbl/d for the three months ended September 30, 2006.

Product purchases increased by $2.3 million, or 3%, to $74.7 million for the three months ended September 30, 2007 compared to $72.4 million for the three months ended September 30, 2006. For the three months ended September 30, 2007 and 2006, product purchases were 69% and 71% of total revenues, respectively.

Operating expenses increased by $0.2 million, or 3%, to $6.6 million for the three months ended September 30, 2007 compared to $6.4 million for the three months ended September 30, 2006.

Depreciation and amortization expense increased by $0.1 million, or 1%, to $14.4 million for the three months ended September 30, 2007 compared to $14.3 million for the three months ended September 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 three months of 2006 and the first nine months of 2007.

General and administrative expense increased by $0.9 million, or 47%, to $2.8 million for the three months ended September 30, 2007 compared to $1.9 million for the three months ended September 30, 2006. For the three months ended September 30, 2007, allocated general and administrative expenses were subject to the $5 million annual cap on general and administrative expense under the Omnibus Agreement. For this period, our general and administrative expenses included $1.3 million of allocated general and administrative expenses and $1.5 million of direct general and administrative expenses. For additional information regarding our allocation of general and administrative costs, please see Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement in our Annual Report on Form 10-K for the year ended December 31, 2006.

Interest expense recorded for the three months ended September 30, 2007 was $5.0 million, which reflects the interest costs associated with borrowings under our revolving credit facility. The decrease in interest expense for the three months ended September 30, 2007 of $13.7 million, or 73%, from $18.7 million for the three months ended September 30, 2006 is due to the repayment of affiliate indebtedness with the proceeds of our IPO and borrowings under our credit facility. The remainder of the affiliate debt was treated as contributed capital by our general and limited partners in conjunction with our IPO.

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 exceeds cost of goods. Accordingly, we have estimated our liability for this tax.

Comparison of Nine Months Ended September 30, 2007 to Nine Months Ended September 30, 2006

Our revenues increased $16.8 million, or 6%, to $307.7 million for the nine months ended September 30, 2007 compared to $290.9 million for the nine months ended September 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 $1.1 million and $3.1 million, respectively, offset by a decrease in NGL revenues of $5.5 million.
- an increase attributable to commodity prices of $15.6 million, consisting of increases in natural gas, NGL and condensate revenues of $8.3 million, $6.7 million and $0.6 million, respectively.
- an increase in revenues from fee based processing activities of $2.5 million.

Average realized prices for natural gas increased by $0.40 per MMBtu (including a $0.38 net increase per MMBtu related to hedging activities), or 7%, to $6.53 per MMBtu for the nine months ended September 30, 2007 compared to $6.13 per MMBtu for the nine months ended September 30, 2006. The average realized price for NGLs increased by $0.04 per gallon (net of a $0.02 decrease per gallon related to hedging activities), or 5%, to $0.92 per gallon for the nine months ended September 30, 2007 compared to $0.88 per gallon for the nine months ended September 30, 2006. The average realized price for condensate increased by $1.30 per Bbl (including a $1.16 net increase per Bbl related to hedging activities), or 2%, to $55.39 per Bbl for the nine months ended September 30, 2007 compared to $54.09 per Bbl for the nine months ended September 30, 2006.

Natural gas sales volumes increased by 0.6 BBtu/d, or 1%, to 75.8 BBtu/d for the nine months ended September 30, 2007 compared to 75.2 BBtu/d for the nine months ended September 30, 2006. The increase in natural gas sales volumes was primarily due to higher field production as a result of new well connections during the last quarter of 2006 and throughout 2007, which was partially offset by significant volume reductions due to cold weather in January 2007 and early February 2007. NGL sales volumes decreased by 0.6 MBbl/d, or 4%, to 13.5 MBbl/d for the nine months ended September 30, 2007 compared to 14.1 MBbl/d for the nine months ended September 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 NGLs products on specification. For the nine months ended September 30, 2007, these changes in operations resulted in decreased NGL recoveries compared to the nine months ended September 30, 2006. Condensate sales volumes increased by 0.2 MBbl/d, or 13%, to 1.8 MBbl/d for the nine months ended September 30, 2007 compared to 1.6 MBbl/d for the nine months ended September 30, 2006.

Product purchases increased by $7.8 million, or 4%, to $213.0 million for the nine months ended September 30, 2007 compared to $205.2 million for the nine months ended September 30, 2006. For the nine months ended September 30, 2007 and 2006, product purchases were 69% and 71% of total revenues, respectively. The increase in product purchases for the nine months ended September 30, 2007 corresponds with the increase in revenues for the same period.

Operating expenses increased by $0.7 million, or 4%, to $18.6 million for the nine months ended September 30, 2007 compared to $17.9 million for the nine months ended September 30, 2006.

Depreciation and amortization expense increased by $1.2 million, or 3%, to $42.9 million for the nine months ended September 30, 2007 compared to $41.7 million for the nine months ended September 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 three months of 2006 and the first nine months of 2007.

General and administrative expense increased by $1.2 million, or 24%, to $6.3 million for the nine months ended September 30, 2007 compared to $5.1 million for the nine months ended September 30, 2006. For the period from February 14, 2007 through September 30, 2007, allocated general and administrative expenses were subject to the $5 million annual cap on general and administrative expense under the Omnibus Agreement. For this period, our general and administrative expenses included $3.8 million of allocated general and administrative expenses and $2.5 million of direct general and administrative expenses. For additional information regarding our allocation of general and administrative costs, please see Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement in our Annual Report on Form 10-K for the year ended December 31, 2006.

Interest expense for the nine months ended September 30, 2007 was $22.7 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 $12.9 million in interest expense for the period from February 14, 2007 through September 30, 2007, reflecting the interest costs associated with borrowings under our revolving credit facility. The decrease in interest expense for the nine months ended September 30, 2007 of $31.7 million, or 58%, from $54.4 million for the nine months ended September 30, 2006 is due to the repayment of affiliate indebtedness with the proceeds of our IPO and borrowings under our credit facility. The remainder of the affiliate debt was treated as contributed capital by our general and limited partners in conjunction with our IPO.

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.

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” in this Quarterly Report.

Historically, our cash generated from operations has been sufficient to finance our operating expenditures and maintenance and expansion capital expenditures, with remaining amounts being distributed to Targa. Our cash receipts were deposited into centralized cash management accounts that were maintained by Targa and all cash disbursements were made from these accounts. Thus, historically, our financial statements have reflected no cash balances. Cash transactions handled by Targa for us were reflected as adjustments to partners' equity. Following our IPO, we maintain our own cash management system, which is managed by Targa.

We expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under our revolving 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 quarterly cash distributions for at least the next year.

On October 24, 2007, we completed the purchase from Targa of its ownership interests in Targa Texas Field Services LP, (the "SAOU" system), and Targa Louisiana Field Services LLC (the "LOU" system). This acquisition consisted of the SAOU systems' natural gas gathering and processing businesses located in the Permian Basin of west Texas and the LOU systems' natural gas gathering and processing businesses located in southwest Louisiana. The total value of the transaction was approximately $705 million, subject to certain post-closing adjustments. In addition, we paid approximately $24.2 million to Targa for the termination of certain hedge transactions. Total consideration paid by us to Targa consisted of cash of approximately $721.7 million and 275,511 general partner units issued to Targa to allow it to maintain its 2% general partner interest in us. Our acquisition of the SAOU and LOU systems will be accounted for under common control accounting. Under common control accounting, the SAOU and LOU systems assets and liabilities are recorded at their book value with the balance of the acquisition proceeds recorded as an adjustment to parent equity.

Concurrent with the acquisition of the SAOU and LOU systems, we entered into a Commitment Increase Supplement (the "supplement") to our existing five-year $500 million senior secured revolving credit facility (described below) to increase the credit facility. The Supplement increased the aggregate commitments under the Credit Agreement by $250 million to an aggregate $750 million. We paid for our acquisition of the SAOU and LOU systems with the proceeds from our offering of common units and borrowings under the increased senior secured revolving credit facility.

On October 24, 2007, we entered into the First Amendment to Credit Agreement (the "Amendment"). The Amendment increased by $250 million the maximum amount of increases to the aggregate commitments that may be requested by us. The Amendment allows us to request commitments under the Credit Agreement, as supplemented and amended, up to $1 billion.

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.

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. 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 September 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) 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.

Any subsequent replacement of our credit agreement or any new indebtedness could have similar or greater restrictions. As of September 30, 2007, we had approximately $205.2 million available under the credit agreement, after giving effect to outstanding borrowings and the issuance of $0.3 million of letters of credit. As of October 24, 2007, after our acquisition of the SAOU and LOU systems, the amendment to our credit facility and borrowings under our credit facility, we had approximately $76.4 million available under the amended credit facility.

Contractual Obligations

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

		Payments Due By Period			
Contractual Obligations	Total	Remaining Three Months of 2007	2008-2009	2010-2011	2012
			(In millions)		
Debt obligations	$ 294.5	$ —	$ —	$ —	$ 294.5
Interest on debt obligations(1)	90.2	5.2	41.2	41.2	2.6
	$ 384.7	$ 5.2	$ 41.2	$ 41.2	$ 297.1

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

Cash Flow

Net cash provided by or used in operating activities, investing activities and financing activities for the nine months ended September 30, 2007 and 2006 were as follows:

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions)	
Net cash provided by operating activities	$ 60.1	$ 11.1
Net cash used in investing activities	(17.3)	(17.7)
Net cash provided by (used in) financing activities	(14.3)	6.6

Operating Activities. Net cash provided by operating activities was $60.1 million for the nine months ended September 30, 2007 compared to $11.1 million for the nine months ended September 30, 2006. The $49.0 million increase in net cash provided by operations was attributable to net income for the nine months ended September 30, 2007 compared to a net loss for the nine months ended September 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 $17.3 million for the nine months ended September 30, 2007 compared to $17.7 million for the nine months ended September 30, 2006. The $0.4 million, or 2%, decrease was primarily attributable to a $0.7 million decrease in capital spending related to expansion expenditures. We categorize our capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance capital expenditures are those expenditures that are necessary to maintain the base level 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 nine months ended September 30, 2007 and 2006.

	Nine Months Ended September 30, 2007	Feb. 14, 2007 to September 30, 2007	Jan. 1, 2007 to Feb. 13, 2007	Nine Months Ended September 30, 2006
		(In millions)		
Capital expenditures:				
Expansion	$ 8.1	$ 6.4	$ 1.7	$ 8.8
Maintenance	9.3	7.8	1.5	9.0
	$ 17.4	$ 14.2	$ 3.2	$ 17.8

Financing Activities. Net cash used in financing activities for the nine months ended September 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 nine months ended September 30, 2006 represents the contribution to us by Targa of the net cash required for principal and interest on allocated parent debt.

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.

Recent Accounting Pronouncements

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

- 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, see Note 2 of the Notes to Consolidated Financial Statements included in Item 1 of this Quarterly Report.

Item 3. ***Quantitative and Qualitative Disclosures about Market Risk***

For an in-depth discussion of market risks, please see Item 7A. Quantitative and Qualitative Disclosure about Market Risk in our Annual Report on Form 10-K for the year ended December 31, 2006.

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 a hedge are classified in the same category as the cash flows from the item being hedged. For an in-depth discussion of our hedging strategies, please see Item 7A. Quantitative and Qualitative Disclosure about Market Risk — Commodity Price Risk — Hedging Strategies in our Annual Report on Form 10-K for the year ended December 31, 2006.

For the three and nine months ended September 30, 2007, net hedging activities increased our operating revenues by $1.1 million and $6.1 million, respectively. For the three and nine months ended September 30, 2006 we had net hedge settlements of $0.3 million. At September 30, 2007, we had the following open commodity derivative positions designated as cash flow hedges:

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	—	—	—	—	—	$ 1,836
Swap	IF-NGPL MC	8.43	—	6,964	—	—	—	—	3,958
Swap	IF-NGPL MC	8.02	—	—	6,256	—	—	—	1,415
Swap	IF-NGPL MC	7.43	—	—	—	5,685	—	—	202
Swap	IF-NGPL MC	7.34	—	—	—	—	2,750	—	72
Swap	IF-NGPL MC	7.18	—	—	—	—	—	2,750	140
			8,152	6,964	6,256	5,685	2,750	2,750	7,623
Swap	IF-Waha	8.73	5,460	—	—	—	—	—	1,258
Swap	IF-Waha	8.53	—	4,657	—	—	—	—	2,053
Swap	IF-Waha	7.96	—	—	4,196	—	—	—	331
Swap	IF-Waha	7.38	—	—	—	3,809	—	—	(262)
Swap	IF-Waha	7.36	—	—	—	—	2,250	—	(35)
Swap	IF-Waha	7.18	—	—	—	—	—	2,250	11
			5,460	4,657	4,196	3,809	2,250	2,250	3,356
Total Swaps			13,612	11,621	10,452	9,494	5,000	5,000	10,979
Floor	IF-NGPL MC	6.45	520	—	—	—	—	—	32
Floor	IF-NGPL MC	6.55	—	1,000	—	—	—	—	267
Floor	IF-NGPL MC	6.55	—	—	850	—	—	—	205
			520	1,000	850	—	—	—	504
Floor	IF-Waha	6.70	350	—	—	—	—	—	25
Floor	IF-Waha	6.85	—	670	—	—	—	—	173
Floor	IF-Waha	6.55	—	—	565	—	—	—	115
			350	670	565	—	—	—	313
Total Floors			870	1,670	1,415	—	—	—	817
									$ 11,796

NGLs

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	—	—	—	—	—	$ (3,925)
Swap	OPIS-MB	0.93	—	2,910	—	—	—	—	(9,492)
Swap	OPIS-MB	0.89	—	—	2,548	—	—	—	(4,542)
Swap	OPIS-MB	0.87	—	—	—	2,159	—	—	(684)
Swap	OPIS-MB	0.90	—	—	—	—	1,250	—	43
Swap	OPIS-MB	0.90	—	—	—	—	—	750	107
			3,416	2,910	2,548	2,159	1,250	750	$ (18,493)

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	—	—	—	—	—	$ (268)
Swap	NY-WTI	70.68	—	384	—	—	—	—	(777)
Swap	NY-WTI	69.00	—	—	322	—	—	—	(491)
Swap	NY-WTI	68.10	—	—	—	301	—	—	(388)
Total Swaps			439	384	322	301	—	—	(1,924)
Floor	NY-WTI	$ 58.60	25	—	—	—	—	—	0
Floor	NY-WTI	60.50	—	55	—	—	—	—	17
Floor	NY-WTI	60.00	—	—	50	—	—	—	37
Total Floors			25	55	50	—	—	—	54
									$ (1,870)

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

Interest Rate Risk

We are exposed to changes in interest rates, as a result of our variable rate debt under our credit facility that we entered into on February 14, 2007. Our revolving credit facility had outstanding borrowings of $294.5 million as of September 30, 2007. A hypothetical 100 basis point increase in the underlying interest rate would increase our annual interest expense by $2.9 million.

Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our customers. We operate under the Targa credit policy and closely monitor the creditworthiness of customers to whom we grant credit and establish credit limits in accordance with this credit policy In addition to third-party contracts, we have entered into several agreements with Targa. For example, we are party to natural gas, NGL and condensate purchase agreements 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.

Item 4. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

Our management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, our disclosure controls and procedures were effective at a reasonable assurance level to provide reasonable assurance that all material information relating to us required to be included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. There has been no change in our internal control over financial reporting during the quarter ended September 30, 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*

The information required for this item is provided in Note 9, Commitments and Contingencies and Note 11, Subsequent Events, under the headings “Litigation” included in the notes to the consolidated financial statements included under Part I, Item 1, which is incorporated by reference into this item.

Item 1A. *Risk Factors*

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are 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 report. .If any of the following risks were actually to occur, then our business, financial condition or results of operations could be materially adversely affected.

On October 18, 2007, we entered into an Underwriting Agreement (the “Underwriting Agreement”) with TR GP and the underwriters named therein providing for the offer and sale in a firm commitment underwritten offering of 13,500,000 common units representing limited partner interests in us at a price of $26.87 per Common Unit ($25.796 per Common Unit, net of underwriting discounts) (the “Offering”). The transactions contemplated by the Underwriting Agreement were consummated on October 24, 2007.

On October 24, 2007, we completed our acquisition (the “Acquisition”) of the SAOU and LOU systems from Targa. Following is an in-depth discussion of our risk factors following the acquisition. These risks and uncertainties are not the only ones facing us and there may be additional matters that we are unaware of or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations, as could the following:

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. 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 for 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 September 30, 2007 the NYMEX daily settlement price for natural gas has ranged from a high of $8.19 per MMBtu to a low of $5.38 per MMBtu. NGL prices exhibit similar volatility. Based on monthly index prices, the average price for our NGL composition for 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 September 30, 2007 the average price for our NGL composition ranged from a high of $1.27 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 nine month period ended September 30, 2007, our percent-of-proceeds arrangements accounted for approximately 80% 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 used the proceeds of our 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 November 1, 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 nine months ended September 30, 2007 were negatively impacted by unseasonably wet weather during the first half of the year, 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 our offering, we had approximately $673.3 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 our offering, we had approximately $673.3 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, 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 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 quarterly report 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.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

Not applicable.

Item 3. ***Defaults Upon Senior Securities***

Not applicable.

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

Not applicable.

Item 5. ***Other Information***

Not applicable.

Item 6. ***Exhibits***

Exhibit Number		Description
2.1*	—	Purchase and Sale Agreement, dated as of September 18, 2007, by and between Targa Resources Partners LP and Targa Resources Holdings LP, incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed September 21, 2007 (File No. 001-33303).
3.1	—	Certificate of Limited Partnership of Targa Resources Partners LP, incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP’s Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747).
3.2	—	Certificate of Formation of Targa Resources GP LLC, incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP’s Registration Statement on Form S-1 filed January 19, 2007 (File No. 333-138747).

Exhibit Number		Description
3.3	—	Agreement of Limited Partnership of Targa Resources Partners LP, incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303).
3.4	—	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303).
3.5	—	Limited Liability Company Agreement of Targa Resources GP LLC, incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1 filed January 19, 2007 (File No. 333-138747).
4.1	—	Specimen Unit Certificate representing common units, incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303).
31.1**	—	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2**	—	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	—	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	—	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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

** Filed herewith

SIGNATURES

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

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

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

Date: November 14, 2007

Exhibit Index

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

** Filed herewith

Exhibit 31.1

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Rene R. Joyce, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the period ended September 30, 2007 of Targa Resources Partners LP;

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

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

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

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

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

Date: November 14, 2007

Exhibit 31.2

Certification Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Jeffrey J. McParland, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the period ended September 30, 2007 of Targa Resources Partners LP;

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

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

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

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

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

Date: November 14, 2007

Exhibit 32.1

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

In connection with the Quarterly Report on Form 10-Q for the period ended September 30, 2007 of Targa Resources Partners LP (the "Partnership") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Rene R. Joyce, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Rene R. Joyce
Name: Rene R. Joyce
Title: Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership

Date: November 14, 2007

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

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

In connection with the Quarterly Report on Form 10-Q for the period ended September 30, 2007 of Targa Resources Partners LP (the "Partnership") as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Jeffrey J. McParland, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Jeffrey J. McParland
Name: Jeffrey J. McParland
Title: Executive Vice President and Chief Financial Officer of Targa Resources GP, LLC,
the general partner of the Partnership

Date: November 14, 2007

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement required by Section 906, has been provided to the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.