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 June 30, 2008**
	or
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the transition period from to**

Commission File Number 001-33303

TARGA RESOURCES PARTNERS LP

(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**65-1295427** *(I.R.S. Employer Identification No.)*
1000 Louisiana, Suite 4300, Houston, Texas *(Address of principal executive offices)*	**77002** *(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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Ruler 12b-2 of the Exchange Act. (Check one):

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

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

There were 34,652,000 Common Units, 11,528,231 Subordinated Units and 942,455 General Partner Units outstanding as of August 1, 2008.

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

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

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

As used in this Quarterly Report, unless the context otherwise requires, "we," "us", "our," the "Partnership" and similar terms refer to Targa Resources Partners LP, together with its consolidated subsidiaries.

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 in this Quarterly Report and our Annual Report on Form 10-K for the year ended December 31, 2007.

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 in this Quarterly Report and under "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2007. 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. ***Financial Statements***

TARGA RESOURCES PARTNERS LP

CONSOLIDATED BALANCE SHEETS

	June 30, 2008	December 31, 2007
	(Unaudited) (In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 31,988	$ 50,994
Receivables from third parties	84,847	59,346
Receivables from affiliated companies	107,367	87,547
Inventory	2,350	1,624
Assets from risk management activities	1,926	8,695
Other current assets	395	269
Total current assets	228,873	208,475
Property, plant and equipment, at cost	1,455,834	1,433,955
Accumulated depreciation	(210,923)	(174,361)
Property, plant and equipment, net	1,244,911	1,259,594
Debt issue costs	12,321	6,588
Long-term assets from risk management activities	3,362	3,040
Other assets	2,285	2,275
Total assets	$ 1,491,752	$ 1,479,972
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 5,616	$ 5,693
Accrued liabilities	198,820	142,836
Liabilities from risk management activities	115,293	44,003
Total current liabilities	319,729	192,532
Long-term debt	575,000	626,300
Long-term liabilities from risk management activities	153,697	43,109
Deferred income taxes	1,259	559
Other long-term liabilities	3,451	3,266
Commitments and contingencies (Note 8)		
Partners' capital:		
Common unitholders (34,652,000 and 34,636,000 units issued and outstanding at June 30, 2008 and December 31, 2007, respectively)	778,039	770,207
Subordinated unitholders (11,528,231 units issued and outstanding at June 30, 2008 and December 31, 2007)	(82,431)	(84,999)
General partner (942,455 and 942,128 units issued and outstanding at June 30, 2008 and December 31, 2007, respectively)	8,424	4,234
Accumulated other comprehensive loss	(265,416)	(75,236)
Total partners' capital	438,616	614,206
Total liabilities and partners' capital	$ 1,491,752	$ 1,479,972

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Unaudited) (In thousands, except per unit amounts)			
Revenues from third parties	$ 243,138	$ 175,149	$ 438,210	$ 315,339
Revenues from affiliates	387,382	258,466	704,379	467,057
Total operating revenues	630,520	433,615	1,142,589	782,396
Costs and expenses:				
Product purchases from third parties	478,890	310,465	854,515	564,619
Product purchases from affiliates	76,269	61,236	142,794	101,580
Operating expenses	14,701	11,795	27,271	23,947
Depreciation and amortization expense	18,421	17,619	36,669	35,657
General and administrative expense	5,715	4,632	10,916	7,986
Gain on sale of assets	(1)	(315)	(75)	(315)
	593,995	405,432	1,072,090	733,474
Income from operations	36,525	28,183	70,499	48,922
Other income (expense):				
Interest expense, net	(7,976)	(5,154)	(16,694)	(7,859)
Interest expense allocated from Parent	—	(2,732)	—	(16,175)
Loss on mark-to-market derivative instruments	—	(6,122)	—	(21,002)
Other	20	(16)	36	5
Income before income taxes	28,569	14,159	53,841	3,891
Deferred income tax expense	363	348	700	707
Net income	28,206	13,811	53,141	3,184
Net income (loss) attributable to predecessor operations	—	9,771	—	(3,009)
Net income allocable to partners	28,206	4,040	53,141	6,193
Net income attributable to general partner interests	3,384	81	5,230	124
Net income available to common and subordinated unitholders	$ 24,822	$ 3,959	$ 47,911	$ 6,069
Basic net income per common and subordinated unit	$ 0.54	$ 0.13	$ 1.04	$ 0.20
Diluted net income per common and subordinated unit	$ 0.54	$ 0.13	$ 1.04	$ 0.20
Basic average number of common and subordinated units outstanding	46,154	30,848	46,152	30,848
Diluted average number of common and subordinated units outstanding	46,163	30,855	46,160	30,854

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(Unaudited) (In thousands)			
Net income	$ 28,206	$ 13,811	$ 53,141	$ 3,184
Other comprehensive loss:				
Commodity hedges:				
Change in fair value of commodity hedges	(168,452)	(7,440)	(220,236)	(33,335)
Reclassification adjustment for settled periods	19,714	(1,004)	29,711	(5,000)
Related income taxes	—	8	—	311
Interest rate swaps:				
Change in fair value of interest rate swaps	9,165	44	(270)	(531)
Reclassification adjustment for settled periods	848	(88)	615	(88)
Other comprehensive loss	(138,725)	(8,480)	(190,180)	(38,643)
Comprehensive income (loss)	$ (110,519)	$ 5,331	$ (137,039)	$ (35,459)

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL

	Accumulated Other Comprehensive Loss	Partners' Capital — Limited Partners — Common	Partners' Capital — Limited Partners — Subordinated	Partners' Capital — General Partner	Total
		(Unaudited) (In thousands)			
Balance as of December 31, 2007	$ (75,236)	$ 770,207	$ (84,999)	$ 4,234	$ 614,206
Other contributions	—	—	—	8	8
Amortization of equity awards	—	119	—	—	119
Other comprehensive loss	(190,180)	—	—	—	(190,180)
Net income	—	35,948	11,963	5,230	53,141
Distributions	—	(28,235)	(9,395)	(1,048)	(38,678)
Balance as of June 30, 2008	$ (265,416)	$ 778,039	$ (82,431)	$ 8,424	$ 438,616

See notes to consolidated financial statements

TARGA RESOURCES PARTNERS LP

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
	(Unaudited) (In thousands)	
Cash flows from operating activities		
Net income	$ 53,141	$ 3,184
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation	36,607	35,596
Amortization	1,038	1,173
Accretion of asset retirement obligations	72	204
Deferred income tax expense	700	707
Risk management activities	1,011	21,087
Gain on sale of assets	(75)	(315)
Changes in operating assets and liabilities:		
Accounts receivable	(45,321)	(7,151)
Inventory	(726)	(270)
Other	(2,992)	(503)
Accounts payable	(77)	2,641
Accrued liabilities	55,984	12,549
Net cash provided by operating activities	99,362	68,902
Cash flows from investing activities		
Purchases of property, plant and equipment	(17,586)	(23,352)
Other	(4,150)	(30)
Net cash used in investing activities	(21,736)	(23,382)
Cash flows from financing activities		
Proceeds from equity offerings	—	380,768
Costs incurred in connection with public offerings	(72)	(3,175)
General partner contributions	8	—
Distributions	(38,678)	(5,315)
Proceeds from borrowings under credit facility	—	342,500
Proceeds from issuance of senior notes	250,000	—
Costs incurred in connection with financing arrangements	(6,590)	(4,145)
Repayments of loans:		
Affiliated	—	(665,692)
Credit facility	(301,300)	(48,000)
Deemed Parent distributions	—	(33,100)
Net cash used in financing activities	(96,632)	(36,159)
Net change in cash and cash equivalents	(19,006)	9,361
Cash and cash equivalents, beginning of period	50,994	—
Cash and cash equivalents, end of period	$ 31,988	$ 9,361
Supplemental cash flow information:		
Net settlement of allocated indebtedness and debt issue costs	$ —	$ 239,065
Net contribution of affiliated receivables	—	38,856

See notes to consolidated financial statements

Targa Resources Partners LP

Notes to Consolidated Financial Statements
(Unaudited)

Note 1 — Organization and Operations

Targa Resources Partners LP ("we", "us", "our" or the "Partnership") is a publicly traded Delaware limited partnership. Our common units are listed on The NASDAQ Stock Market LLC under the symbol "NGLS." We were formed on October 26, 2006 by Targa Resources, Inc. ("Targa" or "Parent"), a leading provider of midstream natural gas and NGL services in the United States, to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. We are engaged in the business of gathering, compressing, treating, processing and selling natural gas and fractionating and selling natural gas liquids ("NGLs") and NGL products. We currently operate in the Fort Worth Basin/Bend Arch in North Texas (the "North Texas system"), the Permian Basin in West Texas (the "SAOU system") and in Southwest Louisiana (the "LOU system").

Note 2 — Basis of Presentation

These unaudited consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements, but does not include all disclosures required by GAAP. The unaudited consolidated financial statements for the three and six month periods ended June 30, 2008 and 2007 include all adjustments, both normal and recurring, which are, in the opinion of management, necessary for a fair statement 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). Our results of operations for the three and six month periods ended June 30, 2007 were adjusted to reflect the consideration of common control accounting and change in predecessor entities as discussed in Notes 4 and 15 in our Annual Report on Form 10-K for the year ended December 31, 2007. Our financial results for the three and six month periods ended June 30, 2008 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2008. 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, 2007.

Note 3 — Accounting Pronouncements

Accounting Pronouncements Recently Adopted.

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

SFAS 157 establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Our derivative instruments consist of financially settled commodity and interest rate swap and option contracts and fixed price commodity contracts with certain customers. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are either readily available in public markets or are quoted by counterparties to these contracts. In situations where we obtain inputs via quotes from our counterparties, we verify the reasonableness of these quotes via similar quotes from another source for each date for which financial statements are presented. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold. We have categorized the inputs for these contracts as Level 2 or Level 3. The price quotes for the Level 3 inputs are provided by a counterparty with whom we regularly transact business.

The fair value of our financial instruments as of June 30, 2008 was:

	Total	Level 1	Level 2	Level 3
		(In thousands)		
Assets from commodity derivative contracts	$ 3,756	$ —	$ 1,939	$ 1,817
Assets from interest rate swaps	1,532	—	1,532	—
Total assets	$ 5,288	$ —	$ 3,471	$ 1,817
Liabilities from commodity derivative contracts	$ 266,572	$ —	$ 72,845	$ 193,728
Liabilities from interest rate swaps	2,418	—	2,418	—
Total liabilities	$ 268,990	$ —	$ 75,263	$ 193,728

The following table sets forth a reconciliation of the changes in the fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts
	(In thousands)
Beginning balance	$ (71,370)
Losses included in other comprehensive income	(148,160)
Settlements	27,619
Transfers in/out of Level 3	—
Ending balance, June 30, 2008	$ (191,911)

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

Accounting Pronouncements Recently Issued

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

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

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

In March 2008, the FASB issued SFAS 161, *"Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133."* SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. Early adoption is encouraged. Our adoption of SFAS 161 will not impact our consolidated financial position, results of operations or cash flows.

Note 4 — Net Income per Limited Partner Unit and Distributions

Our net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner.

Securities that meet the definition of a participating security are required to 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.

These required disclosures do not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds the First Target Distribution Level, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights held by the general partner, even though we make distributions on the basis of Available Cash and not earnings. In periods in which our aggregate net income does not exceed the First Target Distribution Level, there is no impact on our calculation of earnings per limited partner unit. For the three and six months ended June 30, 2008, our aggregate net income per limited partner unit was greater than the First Target Distribution level, and as a result we allocated $2.8 million and $4.2 million in additional earnings to the general partner. For the three months and six months ended June 30, 2007, our aggregate net income per limited partner unit was less than the First Target Distribution, and as a result there was no impact on our calculation of earnings per limited partner unit.

Basic and diluted net income per limited partner unit is calculated by dividing limited partners' interest in net income, less pro forma general partner incentive distributions as described above, by the weighted-average number of outstanding limited partner units during the period.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

The following table shows the distributions that we made to unitholders during the six months ended June 30, 2008:

Quarter Ended	Distribution per Common Unit	Distribution per Subordinated Unit	Date Paid	Total Distribution
				(In thousands)
December 31, 2007	$0.3975	$0.3975	February 14, 2008	$18,792
March 31, 2008	0.4175	0.4175	May 15, 2008	$19,886

See also Note 10 — Subsequent Events regarding subsequent distributions.

The following table illustrates our calculation of net income per common and subordinated partner unit for the three and six months ended June 30, 2008 and 2007:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands)			
Net income	$ 28,206	$ 13,811	$ 53,141	$ 3,184
Less: Net income (loss) attributable to predeccessor operations	—	9,771	—	(3,009)
Net income allocable to partners	28,206	4,040	53,141	6,193
Net income attributable to general partner interests	3,384	81	5,230	124
Net income available to common and subordinated unitholders	$ 24,822	$ 3,959	$ 47,911	$ 6,069
Basic net income per common and subordinated unit	$ 0.54	$ 0.13	$ 1.04	$ 0.20
Diluted net income per common and subordinted unit	$ 0.54	$ 0.13	$ 1.04	$ 0.20
Basic average number of common and subordinated units outstanding	46,154	30,848	46,152	30,848
Restrictive equivalents	9	7	8	6
Diluted average number of common and subordinated units outstanding	46,163	30,855	46,160	30,854

Note 5 — Related-Party Transactions

Targa Resources, Inc.

We are a party to various agreements with Targa, our general partner and others that address (i) the reimbursement of our general partner for costs incurred on our behalf, (ii) our sales of certain NGLs and NGL products to, and purchases from Targa; and (iii) our sales of our natural gas to, and purchases from Targa.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In thousands)		(In thousands)	
Sales to affiliates	$ 387,382	$ 258,466	$ 704,379	$ 467,057
Purchases from affiliates	76,269	61,236	142,794	101,580
Allocations of general & administrative expenses — pre IPO	—	2,679	—	5,157
Allocations of general & administrative expenses under Omnibus Agreement	4,236	1,953	8,098	2,829
Allocated interest	—	2,743	—	16,186
Payments made by Parent on our behalf	—	143,961	—	233,979
Net change in affiliate receivable	4,558	22,062	19,820	50,701

Centralized Cash Management

Prior to the contribution of the North Texas, SAOU and LOU Systems to us, the excess cash from these subsidiaries was held in separate bank accounts and swept to a centralized account under Targa. After the contribution of these systems, their bank accounts are maintained under the Partnership's separate centralized cash management system.

For the North Texas System, prior to February 14, 2007, cash distributions are deemed to have occurred through partners' capital and are reflected as an adjustment to partners' capital. For the period from January 1, 2007 through February 13, 2007, deemed net capital distributions from the Partnership were $0.5 million.

For the SAOU and LOU Systems, for the period from January 1, 2007 though June 30, 2007, deemed net capital distributions from the Partnership were $32.6 million.

Other

Commodity hedges. We have entered into various commodity derivative transactions with Merrill Lynch Commodities Inc. ("MLCI"), an affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated ("Merrill Lynch"). Merrill Lynch holds an equity interest in the holding company that indirectly owns our general partner. Under the terms of these various commodity derivative transactions, MLCI has agreed to pay us specified fixed prices in relation to specified notional quantities of natural gas and condensate over periods ending in 2010, and we have agreed to pay MLCI floating prices based on published index prices of such commodities for delivery at specified locations. The following table shows our open commodity derivatives with MLCI as of June 30, 2008:

Period	Commodity	Instrument Type	Daily Volumes		Average Price		Index
Jul 2008 — Dec 2008	Natural gas	Swap	3,847	MMBtu	$ 8.76	per MMBtu	IF-Waha
Jan 2009 — Dec 2009	Natural gas	Swap	3,556	MMBtu	$ 8.07	per MMBtu	IF-Waha
Jan 2010 — Dec 2010	Natural gas	Swap	3,289	MMBtu	$ 7.39	per MMBtu	IF-Waha
Jul 2008 — Dec 2008	NGL	Swap	3,175	Bbl	$ 1.06	per gallon	OPIS-MB
Jan 2009 — Dec 2009	NGL	Swap	3,000	Bbl	$ 0.98	per gallon	OPIS-MB
Jul 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

As of June 30, 2008, the fair value of these open positions is a liability of $70.4 million. For the three and six months ended June 30, 2008, we paid MLCI $7.4 million and $11.7 million to settle payments due under hedge transactions. For the three and six months ended June 30, 2007, we paid MLCI $1.1 million and $1.8 million to settle payments due under hedge transactions.

Note 6 — Long-Term Debt

Our outstanding debt, including outstanding borrowings, issued letters of credit and available borrowings under our senior secured credit facility as of the dates shown below was:

	June 30, 2008	December 31, 2007
	(In thousands)	
Senior notes, 8 1/4% fixed rate, due July 1, 2016	$ 250,000	$ —
Senior secured credit facility, variable rate, due February 14, 2012	325,000	626,300
Total long-term debt	$ 575,000	$ 626,300
Letters of credit issued	$ 41,250	$ 25,900
Available borrowings under credit facility	$ 483,750	$ 97,800

8 1/4% Senior Notes due 2016

On June 18, 2008, we completed the private placement under Rule 144A and Regulation S of the Securities Act of 1933 (“Rule 144A”) of $250 million in aggregate principal amount of 8 1/4% senior notes due 2016 (the “Notes”). Proceeds from the Notes were used to repay borrowings under our senior secured credit facility.

The Notes:

- are our unsecured senior obligations;
- rank *pari passu* in right of payment with our existing and future senior indebtedness, including indebtedness under our senior secured credit facility;
- are senior in right of payment to any of our future subordinated indebtedness; and
- are unconditionally guaranteed by us.

The Notes are effectively subordinated to all secured indebtedness under our senior secured credit agreement, which is secured by substantially all of our assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the Notes accrues at the rate of 8 1/4% per annum and is payable semi-annually in arrears on January 1, and July 1, commencing on January 1, 2009. Interest is computed on the basis of a 360-day year comprising twelve 30-day months.

At any time prior to July 1, 2011, we may on any one or more occasions redeem up to 35% of the aggregate principal amount of the Notes with the net cash proceeds of one or more equity offerings by us; at a redemption price of 108.25% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date provided that:

(1) at least 65% of the aggregate principal amount of the Notes (including any additional notes) (excluding Notes held by us) remains outstanding immediately after the occurrence of such redemption; and

(2) the redemption occurs within 90 days of the date of the closing of such equity offering.

At any time prior to July 1, 2012, we may also redeem all or a part of the Notes, at a redemption price equal to 100% of the principal amount of the Notes redeemed plus the applicable premium as defined in the indenture agreement, as of, and accrued and unpaid interest and liquidated damages, if any, to the date of redemption.

On or after July 1, 2012, we may redeem all or a part of the Notes, at the redemption prices set forth below (expressed as percentages of principal amount) plus accrued and unpaid interest and liquidated damages, if any, on the Notes redeemed, if redeemed during the twelve-month period beginning on July 1 of each year indicated below:

Year	Percentage
2012	104.125%
2013	102.063%
2014 and thereafter	100.000%

The Notes are subject to a registration rights agreement dated as of June 18, 2008. Under the registration rights agreement, we are required to file by June 19, 2009 a registration statement with respect to any Notes that are not freely transferable without volume restrictions by holders of the Notes that are not affiliates of the Partnership. If we fail to do so, additional interest will accrue on the principal amount of the Notes. Under EITF 00-19-2, *"Accounting for Registration Payment Arrangements,"* we have determined that the payment of additional interest is not probable, as that term is defined in SFAS 5, *"Accounting for Contingencies."* As a result, we have not recorded a liability for any contingent obligation. Any subsequent accruals of a liability or payments made under this registration rights agreement will be charged to earnings as interest expense in the period they are recognized or paid.

Senior Secured Credit Facility

Concurrent with the closing of the private placement of the $250 million senior notes, we increased the commitments under our senior secured credit facility by $100 million, bringing the total commitments under our senior secured credit facility to $850 million. We may still request additional commitments of up to $150 million under the senior secured credit facility, which would increase the total commitments under our senior secured credit facility to $1 billion.

Our weighted average interest rate on outstanding borrowings under our senior secured credit facility for the six months ended June 30, 2008 was 5.0%.

Note 7 — Derivative Instruments and Hedging Activities

As of June 30, 2008 and December 31, 2007, accumulated other comprehensive income (loss) ("OCI") included $264.5 million and $74.0 million of unrealized net losses, respectively, on commodity hedges.

For the three and six months ended June 30, 2008, deferred net losses on commodity hedges of $19.7 million and $29.7 million were reclassified from OCI to revenues, respectively. For the three and six months ended June 30, 2007, deferred net gains on commodity hedges of $1.0 million and $5.0 million were reclassified from OCI to revenues, respectively. There were no adjustments for hedge ineffectiveness.

As of June 30, 2008 and December 31, 2007, OCI also included $0.9 million and $1.2 million of unrealized losses, respectively, on interest rate hedges. For the three and six months ended June 30, 2008, unrealized losses on interest rate hedges of $0.8 million and $0.6 million were reclassified from OCI to interest expense. For the three and six months ended June 30, 2007, unrealized gains on interest rate hedges of $0.1 million were reclassified from OCI to interest expense. There were no adjustments for hedge ineffectiveness.

Targa Resources Partners LP

Notes to Consolidated Financial Statements — (Continued)

As of June 30, 2008, deferred net losses of $111.4 million on commodity hedges and $2.1 million on interest rate hedges recorded in OCI are expected to be reclassified to revenues from third parties and interest expense, respectively, during the next twelve months.

As of June 30, 2008, we had the following hedge arrangements which will settle during the years ended December 31, 2008 through 2012 (except as indicated otherwise, the 2008 volumes reflect daily volumes for the period from July 1, 2008 through December 31, 2008):

Natural Gas

Instrument Type	Index	Avg. Price $/MMBtu	MMBtu per Day 2008	2009	2010	2011	2012	Fair Value (In thousands)
Natural Gas Purchases								
Swap	NY-HH	8.43	1,350	—	—	—	—	$ 1,258
			1,350	—	—	—	—	1,258
Natural Gas Sales								
Swap	IF-HSC	8.09	2,328	—	—	—	—	(2,143)
Swap	IF-HSC	7.39	—	1,966	—	—	—	(3,236)
			2,328	1,966	—	—	—	(5,379)
Swap	IF-NGPL MC	8.43	6,964	—	—	—	—	(4,088)
Swap	IF-NGPL MC	8.02	—	6,256	—	—	—	(7,016)
Swap	IF-NGPL MC	7.43	—	—	5,685	—	—	(5,536)
Swap	IF-NGPL MC	7.34	—	—	—	2,750	—	(2,316)
Swap	IF-NGPL MC	7.18	—	—	—	—	2,750	(2,309)
			6,964	6,256	5,685	2,750	2,750	(21,266)
Swap	IF-Waha	8.20	7,389	—	—	—	—	(5,101)
Swap	IF-Waha	7.61	—	6,936	—	—	—	(9,380)
Swap	IF-Waha	7.38	—	—	5,709	—	—	(5,699)
Swap	IF-Waha	7.36	—	—	—	3,250	—	(2,786)
Swap	IF-Waha	7.18	—	—	—	—	3,250	(2,924)
			7,389	6,936	5,709	3,250	3,250	(25,890)
Total Swaps			16,681	15,158	11,394	6,000	6,000	(51,277)
Floor	IF-NGPL MC	6.55	1,000	—	—	—	—	1
Floor	IF-NGPL MC	6.55	—	850	—	—	—	29
			1,000	850	—	—	—	30
Floor	IF-Waha	6.85	670	—	—	—	—	1
Floor	IF-Waha	6.55	—	565	—	—	—	18
			670	565	—	—	—	19
Total Floors			1,670	1,415	—	—	—	49
								$ (51,228)

NGLs

Instrument Type	Index	Avg. Price $/gal	Barrels per Day 2008	2009	2010	2011	2012	Fair Value (In thousands)
NGL Sales								
Swap	OPIS-MB	1.01	7,095	—	—	—	—	$ (45,341)
Swap	OPIS-MB	0.96	—	6,248	—	—	—	(62,001)
Swap	OPIS-MB	0.91	—	—	4,809	—	—	(40,124)
Swap	OPIS-MB	0.92	—	—	—	3,400	—	(26,650)
Swap	OPIS-MB	0.92	—	—	—	—	2,700	(19,612)
Total Swaps			7,095	6,248	4,809	3,400	2,700	(193,728)
Floors	OPIS-MB	1.73	—	—	—	365	—	860
Floors	OPIS-MB	1.72	—	—	—	—	422	957
Total Floors			—	—	—	365	422	1,817
								$ (191,911)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per Day 2008	2009	2010	2011	2012	Fair Value (In thousands)
Condensate Sales								
Swap	NY-WTI	67.19	384	—	—	—	—	$ (4,922)
Swap	NY-WTI	69.00	—	322	—	—	—	(7,937)
Swap	NY-WTI	68.10	—	—	301	—	—	(6,821)
Total Swaps			384	322	301	—	—	(19,680)
Floor	NY-WTI	60.50	55	—	—	—	—	0
Floor	NY-WTI	60.00	—	50	—	—	—	3
Total Floors			55	50	—	—	—	3
								$ (19,677)

Customer Hedges

Period	Commodity	Instrument Type	Daily Volume	Average Price	Index	Fair Value (In thousands)
Purchases						
Jul 2008 — Dec 2008	Natural gas	Swap	7,043 MMBtu	$ 12.81 per MMBtu	NY-HH	$ 453
Jan 2009 — Dec 2009	Natural gas	Swap	658 MMBtu	11.95 per MMBtu	NY-HH	123
Sales						
Jul 2008 — Dec 2008	Natural gas	Fixed price sale	7,043 MMBtu	12.81 per MMBtu	NY-HH	(453)
Jan 2009 — Dec 2009	Natural gas	Fixed price sale	658 MMBtu	11.95 per MMBtu	NY-HH	(123)
						$ —

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.

See also Note 10 — Subsequent Events regarding termination and rehedging of commodity hedges.

As of June 30, 2008, we had the following open interest rate swaps:

Effective Date	Expiration Date	Rate		Notional Amount (In thousands)
12/13/2007	01/24/2011	4.0775%	$	50,000
12/18/2007	01/24/2011	4.2100%		50,000
12/21/2007	01/24/2012	4.0750%		50,000
12/21/2007	01/24/2012	4.0750%		50,000
01/09/2008	01/24/2012	3.6990%		50,000
01/11/2008	01/24/2012	3.6400%		50,000

Each swap fixes the three month LIBOR rate as indicated for the specified notional amount outstanding under our senior secured credit facility over the term of each swap agreement. The fair value of our outstanding interest rate swaps was a liability of $0.9 million as of June 30, 2008. We have designated all interest rate swaps as cash flow hedges. Accordingly, unrealized gains and losses relating to the interest rate swaps are recorded in OCI until the interest expense on the related debt is recognized in earnings.

Note 8 — Commitments and Contingencies

Environmental

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

Our environmental liability was $0.3 million as of June 30, 2008, primarily for ground water assessment and remediation.

Litigation

On December 8, 2005, WTG Gas Processing ("WTG") filed suit in the 333rd District Court of Harris County, Texas against several defendants, including Targa Resources, Inc., and three other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips Company ("ConocoPhillips") and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase the SAOU system from ConocoPhillips, and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from Targa's competition to purchase the ConocoPhillips' assets and its successful acquisition of those assets in 2004. On October 2, 2007, the District Court granted defendants' motions for summary judgment on all of WTG's claims. Targa has agreed to indemnify us for any claim or liability arising out of the WTG suit. WTG's motion to reconsider and for a new trial was overruled. On January 2, 2008, WTG filed a notice of appeal, and on May 6, 2008 filed its appellant's brief with the 14th Court of Appeals in Houston, Texas. Targa filed its appellee's brief on June 26, 2008. Targa will contest the appeal, but can give no assurances regarding the outcome of the proceeding.

Note 9 — Share-Based Compensation

Our general partner has adopted a long-term incentive plan ("the Plan") for employees, consultants and directors of the general partner and its affiliates who perform services for us. We account for awards under the Plan utilizing the fair value recognition provisions of SFAS 123R, *"Share-Based Payment."*

Non-Employee Director Grants

On March 25, 2008, our general partner made equity-based awards of 16,000 restricted common units of the Partnership (2,000 restricted common units in the Partnership to each of the Partnership's non-management directors and to each of Targa Resources Investments Inc.'s independent directors) under the Plan. The awards will settle with the delivery of common units and are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant date.

Compensation expense on the restricted common units is recognized on a straight-line basis over the vesting period. The fair value of an award of restricted common units is measured on the grant date using the market price of a common unit on such date. For the three and six months ended June 30, 2008, we recognized compensation expense of approximately $78,000 and $119,000 related to equity-based awards, respectively. For the three months ended June 30, 2007 and for the period of commencement of Partnership operations (February 14, 2007) through June 30, 2007, we recognized compensation expense of approximately $60,000 and $76,000 related to equity-based awards, respectively. We estimate that the remaining fair value of $400,000 will be recognized in expense over a weighted average period of approximately two years.

Note 10 — Subsequent Events

During July 2008, we borrowed from our senior secured credit facility $87.4 million to terminate certain out-of-the-money natural gas and NGL commodity swaps. Prior to the terminations, the swaps were designated as hedges in accordance with SFAS 133, *"Derivative Instruments and Hedging Activities*." Deferred losses of approximately $20.8 million, $38.2 million and $27.9 million will be reclassified from OCI as a non-cash reduction of revenue during 2008, 2009 and 2010, respectively, when the hedged forecasted sales transactions are expected to occur. We also entered into new natural gas and NGL commodity swaps at then current market prices that match the production volumes of the terminated swaps through 2010.

On July 23, 2008, our general partner announced a quarterly distribution of available cash of $0.5125 per common and subordinated unit (approximately $25.9 million, including distributions to the general partner and the holder of the incentive distributions rights), for the quarter ended June 30, 2008, payable on August 14, 2008 to unitholders of record as of the close of business on August 4, 2008.

Item 2. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

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 consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2007.

Overview

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

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

Our Operations

We sell the majority of our processed natural gas, NGLs and high pressure condensate to Targa at market-based rates pursuant to natural gas, NGL and condensate purchase agreements. Low-pressure condensate is sold to third parties. 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" in our Annual Report on Form 10-K for the year ended December 31, 2007.

Critical Accounting Policies and Estimates

There have been no significant changes to our critical accounting policies and estimates since December 31, 2007. 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, 2007.

Recent Accounting Pronouncements

On January 1, 2008, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") 157. SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. See Note 3 of the Notes to Unaudited Consolidated Financial Statements for information regarding fair value disclosures pertaining to our financial assets and liabilities.

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

- EITF 07-4, *"Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships."*
- SFAS 161, *"Disclosures about Derivative Instruments and Hedging Activities — an amendment of FASB Statement No. 133."*

For additional information regarding these recent accounting developments and others that may affect our future financial statements, see Note 3 of the Notes to Consolidated Financial Statements included in Item 1 of this Quarterly Report.

Results of Operations

The following table and discussion relate to the three and six months ended June 30, 2008 and 2007 and is a summary of our results of operations for the periods then ended:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions, except operating and price data)			
Revenues	$ 630.5	$ 433.6	$ 1,142.6	$ 782.4
Product purchases	555.2	371.7	997.3	666.2
Operating expense, excluding DD&A	14.7	11.8	27.3	23.9
Depreciation and amortization expense	18.4	17.6	36.7	35.7
General and administrative expense	5.7	4.6	10.9	8.0
Gain on sale of assets	—	(0.3)	(0.1)	(0.3)
Income from operations	36.5	28.2	70.5	48.9
Interest expense, net	(8.0)	(5.2)	(16.7)	(7.8)
Interest expense, allocated from Parent	—	(2.7)	—	(16.2)
Loss on mark-to-market derivative instruments	—	(6.2)	—	(21.0)
Deferred income tax expense	(0.3)	(0.3)	(0.7)	(0.7)
Net income	$ 28.2	$ 13.8	$ 53.1	$ 3.2
Financial data:				
Operating margin(1)	$ 60.7	$ 50.1	$ 118.1	$ 92.3
Adjusted EBITDA(2)	55.5	45.5	108.2	84.8
Distributable cash flow(3)	40.1	33.0	79.6	51.6
Operating data:				
Gathering throughput, MMcf/d(4)	463.9	453.1	463.4	439.2
Plant natural gas inlet, MMcf/d(5)(6)	435.2	427.1	436.4	412.5
Gross NGL production, MBbl/d	44.5	43.2	44.1	41.1
Natural gas sales, BBtu/d(6)	410.0	414.6	414.2	397.5
NGL sales, MBbl/d	39.1	36.5	38.5	34.8
Condensate sales, MBbl/d	3.7	3.7	3.7	3.6
Average realized prices:				
Natural Gas, $/MMBtu				
Average realized sales price	10.52	7.30	9.22	6.97
Impact of hedging	(0.05)	0.06	—	0.07
Average realized price	10.47	7.36	9.22	7.04
NGL, $/gal				
Average realized sales price	1.46	0.97	1.38	0.90
Impact of hedging	(0.11)	(0.01)	(0.09)	—
Average realized price	1.35	0.96	1.29	0.90
Condensate, $/ Bbl				
Average realized sales price	106.17	59.36	96.84	55.34
Impact of hedging	(5.06)	0.90	(3.46)	1.36
Average realized price	101.11	60.26	93.38	56.70

(1) Operating margin is total operating revenues less product purchases and operating expense. See “Non-GAAP Financial Measures.”

(2) Adjusted EBITDA is net income before interest, income taxes, depreciation and amortization and non-cash loss related to derivative instruments. See “Non-GAAP Financial Measures.”

(3) Distributable Cash Flow is net income plus depreciation and amortization and deferred taxes, adjusted for losses (gains) on mark-to-market derivative contracts, less maintenance capital expenditures. See “Non-GAAP Financial Measures.”

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

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

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

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007

Revenues increased $196.9 million, or 45%, to $630.5 million for the three months ended June 30, 2008 compared to $433.6 million for the three months ended June 30, 2007. The increase is primarily due to:

- An increase attributable to commodity prices of $189.1 million, comprising increases in natural gas, NGL and condensate revenues of $115.9 million, $59.3 million and $13.9 million, respectively;
- An increase attributable to commodity sales volume of $6.4 million comprising a decrease in natural gas revenues of $3.1 million, flat condensate revenues, and an increase in NGL revenues of $9.5 million, and
- An increase in other revenue of $1.4 million, primarily from miscellaneous processing activities.

Average realized prices for natural gas increased by $3.11 per MMBtu (net of an $0.11 decrease related to hedge settlements), or 42%, to $10.47 per MMBtu for the three months ended June 30, 2008 compared to $7.36 per MMBtu for the three months ended June 30, 2007. The average realized price for NGLs increased by $0.39 per gallon (net of a $0.10 decrease related to hedge settlements), or 41%, to $1.35 per gallon for the three months ended June 30, 2008 compared to $0.96 per gallon for the three months ended June 30, 2007. The average realized price for condensate increased by $40.85 per barrel (net of a $5.96 decrease related to hedge settlements), or 68%, to $101.11 per barrel for the three months ended June 30, 2008 compared to $60.26 per barrel for the three months ended June 30, 2007.

Natural gas sales volumes decreased by 4.6 BBtu/d, or 1%, to 410.0 BBtu/d for the three months ended June 30, 2008 compared to 414.6 BBtu/d for the three months ended June 30, 2007. The decrease in natural gas sales volumes were attributable to volume decreases in purchases from affiliates for resale.

NGL sales volumes increased by 2.6 MBbl/d, or 7%, to 39.1 MBbl/d for the three months ended June 30, 2008 compared to 36.5 MBbl/d for the three months ended June 30, 2007. The increase was primarily due to increased plant inlet volume of 8.1 MMcf/d as a result of new well connects and increased producer production.

Product purchases increased by $183.5 million, or 49%, to $555.2 million for the three months ended June 30, 2008 compared to $371.7 million for the three months ended June 30, 2007. The increase in product purchase cost was due primarily to higher commodity prices in the three months ended June 30, 2008 versus the three months ended June 30, 2007, partially offset by a volume decrease in gas purchases. Natural gas index prices increased an average of 48.2% for the comparative periods.

Operating expenses increased by $2.9 million, or 25%, to $14.7 million for the three months ended June 30, 2008 compared to $11.8 million for the three months ended June 30, 2007. The increase in operating expenses was primarily the result of increases in compensation related expenses of $1.4 million, utility costs of $0.5 million and other maintenance and supplies costs of $0.9 million.

General and administrative expenses increased by $1.1 million, or 24%, to $5.7 million for the three months ended June 30, 2008 compared to $4.6 million for the three months ended June 30, 2007. The increase consisted primarily of $0.3 million in professional services fees and $0.5 million in the allocation of corporate level expenses. For additional information regarding our allocation of general and administrative costs, see "Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement" in our Annual Report on Form 10-K for the year ended December 31, 2007.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Revenues increased $360.2 million, or 46%, to $1,142.6 million for the six months ended June 30, 2008 compared to $782.4 million for the six months ended June 30, 2007. The increase is primarily due to:

- An increase attributable to commodity prices of $305.3 million, comprising increases in natural gas, NGL and condensate revenues of $164.7 million, $115.4 million and $25.2 million, respectively;
- An increase attributable to commodity sales volume of $52.9 million comprising increases in natural gas, NGL and condensate revenues of $24.2 million, $27.2 million and $1.5 million, respectively; and
- An increase in other revenue of $2.0 million, primarily from miscellaneous processing activities.

Average realized prices for natural gas increased by $2.18 per MMBtu (net of a $0.07 decrease related to hedge settlements), or 31%, to $9.22 per MMBtu for the six months ended June 30, 2008 compared to $7.04 per MMBtu for the six months ended June 30, 2007. The average realized price for NGLs increased by $0.39 per gallon (net of a $0.09 decrease related to hedge settlements), or 43%, to $1.29 per gallon for the six months ended June 30, 2008 compared to $0.90 per gallon for the six months ended June 30, 2007. The average realized price for condensate increased by $36.68 per barrel (net of a $4.82 decrease related to hedge settlements), or 65%, to $93.38 per for the six months ended June 30, 2008 compared to $56.70 per barrel for the six months ended June 30, 2007.

Natural gas sales volumes increased by 16.7 BBtu/d, or 4%, to 414.2 BBtu/d for the six months ended June 30, 2008 compared to 397.5 BBtu/d for the six months ended June 30, 2007. Sales volume increases were attributable to increased demand by our industrial customers, partially offset by increases in residue take-in-kind volumes.

NGL sales volumes increased by 3.7 MBbl/d, or 11%, to 38.5 MBbl/d for the six months ended June 30, 2008 compared to 34.8 MBbl/d for the six months ended June 30, 2007. The increase was primarily due to increased plant inlet through put of 23.9 MMcf/d as a result of new well connects and increased producer production.

Product purchases increased by $331.1 million, or 50%, to $997.3 million for the six months ended June 30, 2008 compared to $666.2 million for the six months ended June 30, 2007. The increase in product purchases was due primarily to increased sales volumes and higher commodity prices in the six months ended June 30, 2008 versus the six months ended June 30, 2007. Natural gas index prices increased an average of 24.6% for the comparative periods.

Operating expenses increased by $3.4 million, or 14%, to $27.3 million for the six months ended June 30, 2008 compared to $23.9 million for the six months ended June 30, 2007. The increase in operating expenses was primarily the result of increases in compensation related expenses of $2.0 million, utility costs of $0.5 million and other maintenance and supplies costs of $0.9 million.

General and administrative and other expenses increased by $2.9 million, or 36%, to $10.9 million for the six months ended June 30, 2008 compared to $8.0 million for the six months ended June 30, 2007. The increase consisted primarily of $0.8 million in professional services fees and $1.7 million in the allocation of corporate level expenses. For additional information regarding our allocation of general and administrative costs, see "Item 13. Certain Relationships and Related Transactions, and Director Independence — Omnibus Agreement" in our Annual Report on Form 10-K for the year ended December 31, 2007.

Liquidity and Capital Resources

Our ability to finance our operations, including to fund 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. See “Item 1A. Risk Factors” in this Quarterly Report and in our Annual Report on Form 10-K for the year ended December 31, 2007.

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

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

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

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect that we will rely upon external financing sources, including other debt and common unit issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs. Historically, we have relied on internally generated cash flows for these purposes. During the six months ended June 30, 2008, we made the following distributions:

Quarter Ended	Distribution per Common Unit	Annualized Distribution	Distribution per Subordinated Unit	Date Paid	Total Distribution (In millions)
December 31, 2007	$ 0.3975	$ 1.59	$ 0.3975	February 14, 2008	$ 18.8
March 31, 2008	0.4175	1.67	0.4175	May 15, 2008	19.9

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 from 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.

As of June 30, 2008, we had a working capital deficit of $90.9 million, including a net short-term liability for commodity and interest rate derivatives of $113.4 million. In accordance with SFAS 133 *“Accounting for Derivative Instruments and Hedging Activities”*, we record the fair value of all derivative instruments on the balance sheet. Our hedge agreements provide for monthly settlement (quarterly for interest rate swaps) based on the differential between the agreement price and published commodity price and interest rate indexes. Cash received from physical sales of commodities and cash paid for interest will be based on actual market prices and interest rates and will generally offset any gains or losses realized on the derivative instruments. Our derivative contracts do not have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date. Excluding derivatives our working capital surplus was $22.5 million. See "Item 3. Quantitative and Qualitative Disclosures about Market Risk" in this Quarterly Report and in our Annual Report on Form 10-K for the year ended December 31, 2007.

Cash Flow. Net cash provided by or used in operating activities, investing activities and financing activities for the six months ended June 30, 2008 and 2007 were as follows:

	Six Months Ended June 30,	
	2008	2007
	(In millions)	
Net cash provided by operating activities	$ 99.4	$ 68.9
Net cash used in investing activities	(21.7)	(23.4)
Net cash used in financing activities	(96.6)	(36.2)

Operating Activities. Net cash provided by operating activities increased by $30.5 million, or 44%, for the six months ended June 30, 2008 compared to the six months ended June 30, 2007. This increase is primarily attributable to an increase in our net income, adjusted for non-cash charges related to risk management activities and other non-cash charges, as presented in the combined statements of cash flows.

Investing Activities. Net cash used in investing activities for the six months ended June 30, 2008 decreased $1.7 million, or 7%, compared to the six months ended June 30, 2007. Purchases of property, plant and equipment during the six months ended June 30, 2008 versus the six months ended June 30, 2007 were down due to the timing of expansion capital projects. Other investing activities for the six months ended June 30, 2008 included approximately $4.2 million for contractually obligated line fill on a third party owned pipeline.

Financing Activities. Net cash used in financing activities increased $60.4 million to $96.6 million for the six months ended June 30, 2008 compared to the six months ended June 30, 2007. Net cash used in financing activities for the six months ended June 30, 2008 is primarily associated with distributions to unitholders of $38.7 million and the repayment of $301.3 million on our senior secured credit facility, which was offset by the net proceeds of $243.4 million from our issuance of the $8^1/_4$% Senior Notes due 2016 ("the Notes"). The net cash used in financing activities for the six months ended June 30, 2007 is primarily associated with the completion of our IPO, the establishment of our senior secured credit facility, deemed parent contribution prior to the IPO and subsequent drop down of assets to us and the contribution of the North Texas System to us, which were offset by payments of debt, offering costs and debt issuance costs related to our senior secured credit facility.

Contractual Obligations. In June 2008, we issued $250 million aggregate principal amount of the Notes. The proceeds from the offering were used to reduce outstanding indebtedness under our senior secured credit facility. The interest rate on the Notes is fixed at 8.25% with interest to be paid on January 1 and July 1 of each year and the Notes mature on July 1, 2016.

Available Credit. As of June 30, 2008, we had approximately $483.8 million in capacity available under our senior secured credit facility, after giving effect to outstanding borrowings of $325.0 million and the issuance of $41.2 million of letters of credit. Our senior secured credit facility allows us to request increases in the commitments under the facility by up to $150 million.

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 continue to incur significant expenditures throughout 2008 related to the expansion of our natural gas gathering and processing infrastructure.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions)			
Capital expenditures:				
Expansion	$ 3.1	$ 6.4	$ 6.1	$ 13.3
Maintenance	7.4	5.1	11.8	10.0
	$ 10.5	$ 11.5	$ 17.9	$ 23.3

We estimate that our total capital expenditures for 2008 will be approximately $70 million. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that we will invest significant amounts of capital to grow and acquire assets. Expansion capital expenditures may vary significantly based on investment opportunities.

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

Non-GAAP Financial Measures

For a complete discussion of the measures that management uses to evaluate our operations, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — How We Evaluate our Operations" in our Annual Report on Form 10-K for the year ended December 31, 2007. The following tables reconcile the non-GAAP financial measures used by management to their most directly comparable GAAP measures for the three and six months ended June 30, 2008 and 2007:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(In millions)			
Reconciliation of "Adjusted EBITDA" to net cash provided by operating activities:				
Net cash provided by operating activities	$ 46.6	$ 25.3	$ 99.4	$ 68.9
Allocated interest expense from parent(1)	—	2.4	—	15.2
Interest expense, net(1)	7.5	5.2	15.8	7.9
Changes in operating working capital which used (provided) cash:				
Accounts receivable and other	43.5	25.0	48.9	7.9
Accounts payable	(1.1)	0.2	0.1	(2.6)
Accrued liabilities	(41.0)	(12.6)	(56.0)	(12.5)
Adjusted EBITDA	$ 55.5	$ 45.5	$ 108.2	$ 84.8
Reconciliation of "Adjusted EBITDA" to net income (loss):				
Net income (loss)	28.2	$ 13.8	$ 53.1	$ 3.2
Add:				
Allocated interest expense, net	—	2.7	—	16.2
Interest expense, net	8.0	5.2	16.7	7.9
Deferred income tax expense	0.4	0.3	0.7	0.7
Depreciation and amortization expense	18.4	17.6	36.7	35.7
Risk Management Activities	0.5	5.9	1.0	21.1
Adjusted EBITDA	$ 55.5	$ 45.5	$ 108.2	$ 84.8
Reconciliation of "operating margin" to net income (loss):				
Net income (loss)	$ 28.2	$ 13.8	$ 53.1	$ 3.2
Add:				
Depreciation and amortization expense	18.4	17.6	36.7	35.7
Deferred income tax expense	0.4	0.3	0.7	0.7
Allocated interest expense, net	—	2.7	—	16.2
Interest expense, net	8.0	5.2	16.7	7.9
Non-cash gain related to derivative instruments	—	6.1	—	21.0
General and administrative and other expense	5.7	4.4	10.9	7.6
Operating margin	$ 60.7	$ 50.1	$ 118.1	$ 92.3

(1) Net of amortization of debt issue costs of $0.5 million and $0.9 million for the three and six months June 30, 2008 and $0.3 million and $1.0 million for the three and six months ended June 30, 2007.

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007(1)	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007(1)
	(In millions)			
Reconciliation of "distributable cash flow" to "net income":				
Net income	$ 28.2	$ 13.8	$ 53.1	$ 3.2
Depreciation and amortization expense	18.4	17.6	36.7	35.7
Deferred income tax expense	0.4	0.3	0.7	0.7
Amortization of debt issue costs	0.5	0.3	0.9	1.0
Loss on mark-to-market derivative instruments	—	6.1	—	21.0
Maintenance capital expenditures	(7.4)	(5.1)	(11.8)	(10.0)
Distributable Cash Flow	$ 40.1	$ 33.0	$ 79.6	$ 51.6

(1) Distributable cash flow for the three and six months ended June 30, 2007 reflects allocated interest from Parent of $2.7 million and $16.2 million, respectively.

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

	For the Six Months Ended June 30, 2007			
		Pre-Acquisition		Post Acquisition
	TRP LP	SAOU-LOU Jan 1, 2007 to June 30, 2007	North Texas Jan 1, 2007 to Feb 13, 2007	TRP LP
	(In millions)			
Net income (loss)	$ 3.2	$ 3.9	$ (6.9)	$ 6.2
Depreciation and amortization expense	35.7	7.2	6.9	21.6
Deferred income tax expense	0.7	—	—	0.7
Amortization of debt issue costs	1.0	0.7	—	0.3
Loss on mark-to-market derivative instruments	21.0	21.0	—	—
Maintenance capital expenditures	(10.0)	(4.8)	(1.5)	(3.7)
Distributable Cash Flow	$ 51.6	$ 28.0	$ (1.5)	$ 25.1

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

For an in-depth discussion of market risks, see "Item 7A. Quantitative and Qualitative Disclosure about Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2007.

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

Commodity Price Risk. A majority of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the natural gas and/or NGLs, or equity volumes, as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as 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, see "Item 7A. Quantitative and Qualitative Disclosure about Market Risk — Commodity Price Risk" in our Annual Report on Form 10-K for the year ended December 31, 2007.

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

For the six months ended June 30, 2008, our operating revenues were decreased by net hedge settlements of $30.3 million. During 2006 through 2008, we entered into hedging arrangements for a portion of our forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). As of June 30, 2008, we had the following open commodity derivative positions (except as indicated otherwise, the 2008 volumes reflect daily volumes for the period from July 1, 2008 through December 31, 2008):

Natural Gas

		Avg. Price	MMBtu per day					
Instrument Type	**Index**	**$/MMBtu**	**2008**	**2009**	**2010**	**2011**	**2012**	**Fair Value (In thousands)**
Natural Gas Purchases								
Swap	NY-HH	8.43	1,350	—	—	—	—	$ 1,258
			1,350	—	—	—	—	1,258
Natural Gas Sales								
Swap	IF-HSC	8.09	2,328	—	—	—	—	(2,143)
Swap	IF-HSC	7.39	—	1,966	—	—	—	(3,236)
			2,328	1,966	—	—	—	(5,379)
Swap	IF-NGPL MC	8.43	6,964	—	—	—	—	(4,088)
Swap	IF-NGPL MC	8.02	—	6,256	—	—	—	(7,016)
Swap	IF-NGPL MC	7.43	—	—	5,685	—	—	(5,536)
Swap	IF-NGPL MC	7.34	—	—	—	2,750	—	(2,316)
Swap	IF-NGPL MC	7.18	—	—	—	—	2,750	(2,309)
			6,964	6,256	5,685	2,750	2,750	(21,266)
Swap	IF-Waha	8.20	7,389	—	—	—	—	(5,101)
Swap	IF-Waha	7.61	—	6,936	—	—	—	(9,380)
Swap	IF-Waha	7.38	—	—	5,709	—	—	(5,699)
Swap	IF-Waha	7.36	—	—	—	3,250	—	(2,786)
Swap	IF-Waha	7.18	—	—	—	—	3,250	(2,924)
			7,389	6,936	5,709	3,250	3,250	(25,890)
Total Swaps			16,681	15,158	11,394	6,000	6,000	(51,277)
Floor	IF-NGPL MC	6.55	1,000	—	—	—	—	1
Floor	IF-NGPL MC	6.55	—	850	—	—	—	29
			1,000	850	—	—	—	30
Floor	IF-Waha	6.85	670	—	—	—	—	1
Floor	IF-Waha	6.55	—	565	—	—	—	18
			670	565	—	—	—	19
Total Floors			1,670	1,415	—	—	—	49
								$ (51,228)

NGLs

Instrument Type	Index	Avg. Price $/gal	Barrels per day 2008	2009	2010	2011	2012	Fair Value (In thousands)
NGL Sales								
Swap	OPIS-MB	1.01	7,095	—	—	—	—	$ (45,341)
Swap	OPIS-MB	0.96	—	6,248	—	—	—	(62,001)
Swap	OPIS-MB	0.91	—	—	4,809	—	—	(40,124)
Swap	OPIS-MB	0.92	—	—	—	3,400	—	(26,650)
Swap	OPIS-MB	0.92	—	—	—	—	2,700	(19,612)
Total Swaps			7,095	6,248	4,809	3,400	2,700	(193,728)
Floors	OPIS-MB	1.73	—	—	—	365	—	860
Floors	OPIS-MB	1.72	—	—	—	—	422	957
Total Floors			—	—	—	365	422	1,817
								$ (191,911)

Condensate

Instrument Type	Index	Avg. Price $/Bbl	Barrels per day 2008	2009	2010	2011	2012	Fair Value (In thousands)
Condensate Sales								
Swap	NY-WTI	67.19	384	—	—	—	—	$ (4,922)
Swap	NY-WTI	69.00	—	322	—	—	—	(7,937)
Swap	NY-WTI	68.10	—	—	301	—	—	(6,821)
Total Swaps			384	322	301	—	—	(19,680)
Floor	NY-WTI	60.50	55	—	—	—	—	0
Floor	NY-WTI	60.00	—	50	—	—	—	3
Total Floors			55	50	—	—	—	3
								$ (19,677)

Customer Hedges

Period	Commodity	Instrument Type	Daily Volume	Average Price	Index	Fair Value (In thousands)
Purchases						
Jul 2008 — Dec 2008	Natural gas	Swap	7,043 MMBtu	$ 12.81 per MMBtu	NY-HH	$ 453
Jan 2009 — Dec 2009	Natural gas	Swap	658 MMBtu	11.95 per MMBtu	NY-HH	123
Sales						
Jul 2008 — Dec 2008	Natural gas	Fixed price sale	7,043 MMBtu	12.81 per MMBtu	NY-HH	(453)
Jan 2009 — Dec 2009	Natural gas	Fixed price sale	658 MMBtu	11.95 per MMBtu	NY-HH	(123)
						$ —

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.

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Interest Rate Risk

We are exposed to changes in interest rates, primarily as a result of variable rate debt under our senior secured credit facility. To the extent that interest rates increase, interest expense on our revolving debt will also increase. As of June 30, 2008, there were borrowings of approximately $325 million outstanding under our $850 million senior secured credit facility and we had the following open interest rate swaps:

Effective Date	Expiration Date	Rate	Notional Amount (In thousands)
12/13/2007	01/24/2011	4.0775%	$ 50,000
12/18/2007	01/24/2011	4.2100%	50,000
12/21/2007	01/24/2012	4.0750%	50,000
12/21/2007	01/24/2012	4.0750%	50,000
01/09/2008	01/24/2012	3.6990%	50,000
01/11/2008	01/24/2012	3.6400%	50,000

Each swap fixes the three month LIBOR rate as indicated for the specified notional amount outstanding under our senior secured credit facility over the term of each swap agreement. The fair value of our outstanding interest rate swaps was a liability of $0.9 million as of June 30, 2008. We have designated all interest rate swaps as cash flow hedges. Accordingly, unrealized gains and losses relating to the interest rate swaps are recorded in OCI until the interest expense on the related debt is recognized in earnings. A hypothetical increase of 100 basis points in the underlying interest rate, after taking into account our interest rate swaps, would increase our annual interest expense by $250 thousand.

Credit Risk

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

Item 4T. *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 controls over financial reporting during the three or six months ended June 30, 2008 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 8, Commitments and Contingencies, under the heading "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***

For an in-depth discussion of our risk factors, see "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2007. 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:

We have a substantial amount of indebtedness which could adversely affect our financial position.

We currently have a substantial amount of indebtedness. As of June 30, 2008 we have approximately $575 million of total indebtedness outstanding**,** approximately $41 million of letters of credit outstanding and approximately $484 million of additional borrowing capacity under our senior secured credit facility. Our senior secured credit facility allows us to request increases in the commitments under the facility by up to $150 million. We may also incur additional indebtedness in the future.

Our substantial indebtedness may:

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

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

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure you that we will generate sufficient cash flow from operations or that future borrowings will be available to us under our credit agreement or otherwise in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

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
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
3.4	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's current report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.5	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.6	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Indenture dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's current report on Form 8-K filed June 18, 2008 (File No 001-33303)).
4.2	Registration Rights Agreement dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's current report on Form 8-K filed June 18, 2008 (File No. 001-33303)).
10.1	Purchase Agreement dated June 12, 2008 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's current report on Form 8-K filed June 18, 2008 (File No. 001-33303)).
10.2	Commitment Increase Supplement, dated June 18, 2008, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's current report on Form 8-K filed June 24, 2008 (File No. 001-33303)).
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1*	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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: August 11, 2008

Exhibit Index

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
3.4	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's current report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.5	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.6	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Indenture dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's current report on Form 8-K filed June 18, 2008 (File No 001-33303)).
4.2	Registration Rights Agreement dated June 18, 2008, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's current report on Form 8-K filed June 18, 2008 (File No. 001-33303)).
10.1	Purchase Agreement dated June 12, 2008 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's current report on Form 8-K filed June 18, 2008 (File No. 001-33303)).
10.2	Commitment Increase Supplement, dated June 18, 2008, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's current report on Form 8-K filed June 24, 2008 (File No. 001-33303)).
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1*	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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 June 30, 2008 of Targa Resources Partners LP;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

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

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

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

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

Date: August 11, 2008

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

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 June 30, 2008 of Targa Resources Partners LP;

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

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

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

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

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

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

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

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

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

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

Date: August 11, 2008

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)

**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 June 30, 2008 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, 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.

Date: August 11, 2008

By: */s/ Rene R. Joyce*

Name: **Rene R. Joyce**

Title: **Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)**

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.

**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 June 30, 2008 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, 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.

Date: August 11, 2008

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)**

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.