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

FORM 10-Q

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

For the quarterly period ended September 30, 2012

or

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

For the transition period from _____ to _____

Commission File Number: 001-33303

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes R No £.

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

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

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

As of October 29, 2012, there were 89,170,989 Common Units and 1,819,817 General Partner Units outstanding.

PART I—FINANCIAL INFORMATION

PART II—OTHER INFORMATION

SIGNATURES

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Part II – Other Information, Item 1A. Risk Factors." of this Quarterly Report on Form 10-Q ("Quarterly Report") as well as the following risks and uncertainties:

- our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity risks;
- the level of creditworthiness of counterparties to transactions;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL") and other commodity prices, interest rates and demand for our services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- the level and success of oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems and NGL supplies to our logistics and marketing facilities and our success in connecting our facilities to transportation and markets;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described elsewhere in "Part II–Other Information, Item 1A. Risk Factors." of this Quarterly Report, our Annual Report on Form 10-K for the year ended December 31, 2011 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

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 "Part II – Other Information, Item 1A. Risk Factors." in this Quarterly Report and in our Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

Table of Contents

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

Bbl	Barrels (equal to 42 gallons)
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
NYSE	New York Stock Exchange
Price Index Definitions	
IF-NGPL MC	Inside FERC Gas Market Report, Natural Gas Pipeline, Mid-Continent
IF-PB	Inside FERC Gas Market Report, Permian Basin
IF-WAHA	Inside FERC Gas Market Report, West Texas WAHA
NY-WTI	NYMEX, West Texas Intermediate Crude Oil
OPIS-MB	Oil Price Information Service, Mont Belvieu, Texas

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	September 30, 2012	December 31, 2011
	(Unaudited) (In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 88.9	$ 55.6
Trade receivables, net of allowances of $1.8 million and $2.2 million	415.9	575.9
Inventory	84.3	92.1
Assets from risk management activities	33.7	41.0
Other current assets	1.1	2.7
Total current assets	623.9	767.3
Property, plant and equipment	4,162.0	3,786.9
Accumulated depreciation	(1,112.1)	(980.8)
Property, plant and equipment, net	3,049.9	2,806.1
Long-term assets from risk management activities	11.1	10.9
Investment in unconsolidated affiliate	51.0	36.8
Other long-term assets	35.0	36.9
Total assets	$ 3,770.9	$ 3,658.0
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 472.1	$ 647.8
Accounts payable to Targa Resources Corp.	47.6	60.0
Liabilities from risk management activities	6.0	41.1
Total current liabilities	525.7	748.9
Long-term debt	1,661.7	1,477.7
Long-term liabilities from risk management activities	7.2	15.8
Deferred income taxes	10.7	9.5
Other long-term liabilities	46.7	44.4
Commitments and contingencies (see Note 10)		
Owners' equity:		
Common unitholders (89,170,989 and 84,756,009 units issued and outstanding as of September 30, 2012 and December 31, 2011)	1,316.5	1,221.2
General partner (1,819,817 and 1,729,715 units issued and outstanding as of September 30, 2012 and December 31, 2011)	34.5	27.2
Accumulated other comprehensive income (loss)	20.9	(25.6)
	1,371.9	1,222.8
Noncontrolling interests in subsidiaries	147.0	138.9
Total owners' equity	1,518.9	1,361.7
Total liabilities and owners' equity	$ 3,770.9	$ 3,658.0

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(Unaudited) (In millions, except per unit amounts)			
Revenues	$ 1,392.9	$ 1,712.7	$ 4,356.8	$ 5,053.8
Costs and expenses:				
Product purchases	1,153.0	1,485.5	3,611.7	4,364.5
Operating expenses	78.3	76.5	227.1	214.1
Depreciation and amortization expenses	47.9	45.0	142.1	132.2
General and administrative expenses	33.5	33.7	100.0	98.6
Other operating (income) expense (See Note 11)	18.9	(0.3)	18.8	(0.4)
Income from operations	61.3	72.3	257.1	244.8
Other income (expense):				
Interest expense, net	(29.0)	(25.7)	(87.8)	(80.4)
Equity earnings (loss)	(2.2)	2.2	(0.3)	5.2
Loss on mark-to-market derivative instruments	-	(1.8)	-	(5.0)
Other	(1.1)	(0.6)	(1.6)	(0.8)
Income before income taxes	29.0	46.4	167.4	163.8
Income tax expense:				
Current	(0.5)	(2.4)	(1.5)	(4.6)
Deferred	(0.4)	0.9	(1.2)	(0.6)
	(0.9)	(1.5)	(2.7)	(5.2)
Net income	28.1	44.9	164.7	158.6
Less: Net income attributable to noncontrolling interests	3.9	9.0	23.5	29.6
Net income attributable to Targa Resources Partners LP	$ 24.2	$ 35.9	$ 141.2	$ 129.0
Net income attributable to general partner	16.7	9.5	46.2	26.0
Net income attributable to limited partners	7.5	26.4	95.0	103.0
Net income attributable to Targa Resources Partners LP	$ 24.2	$ 35.9	$ 141.2	$ 129.0
Net income per limited partner unit - basic and diluted	$ 0.08	$ 0.31	$ 1.07	$ 1.23
Weighted average limited partner units outstanding - basic	89.2	84.8	88.8	83.9
Weighted average limited partner units outstanding - diluted	89.3	84.8	88.9	83.9

See notes to consolidated financial statements.

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

	Three Months Ended September 30,					
	2012			2011		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income			$ 28.1			$ 44.9
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ (22.5)	$ 0.2	(22.3)	$ 47.0	$ -	47.0
Settlements reclassified to revenues	(14.8)	0.2	(14.6)	10.3	-	10.3
Interest rate swaps:						
Change in fair value	-	-	-	(2.3)	-	(2.3)
Settlements reclassified to interest expense, net	1.9	-	1.9	1.0	-	1.0
Other comprehensive income (loss)	$ (35.4)	$ 0.4	(35.0)	$ 56.0	$ -	56.0
Comprehensive income (loss)			(6.9)			100.9
Less: Comprehensive income attributable to noncontrolling interests			3.9			9.0
Comprehensive income (loss) attributable to Targa Resources Partners LP			$ (10.8)			$ 91.9

	Nine Months Ended September 30,					
	2012			2011		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income			$ 164.7			$ 158.6
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ 70.4	$ -	70.4	$ (9.7)	$ -	(9.7)
Settlements reclassified to revenues	(30.0)	-	(30.0)	26.7	-	26.7
Interest rate swaps:						
Change in fair value	-	-	-	(4.3)	-	(4.3)
Settlements reclassified to interest expense, net	6.1	-	6.1	5.7	-	5.7
Other comprehensive income	$ 46.5	$ -	46.5	$ 18.4	$ -	18.4
Comprehensive income			211.2			177.0
Less: Comprehensive income attributable to noncontrolling interests			23.5			29.6
Comprehensive income attributable to Targa Resources Partners LP			$ 187.7			$ 147.4

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Limited Partner		General Partner		Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Units	Amount	Units	Amount			
	(Unaudited) (In millions, except units in thousands)						
Balance, December 31, 2011	84,756	$ 1,221.2	1,730	$ 27.2	$ (25.6)	$ 138.9	$ 1,361.7
Compensation on equity grants	10	2.2	-	-	-	-	2.2
Proceeds from equity offerings	4,405	164.9	90	3.4	-	-	168.3
Contributions from Targa Resources Corp.	-	0.8	-	0.1	-	-	0.9
Distributions to noncontrolling interests	-	(1.1)	-	-	-	(18.6)	(19.7)
Contributions from noncontrolling interests	-	-	-	-	-	3.2	3.2
Other comprehensive income	-	-	-	-	46.5	-	46.5
Net income	-	95.0	-	46.2	-	23.5	164.7
Distributions to unitholders	-	(166.5)	-	(42.4)	-	-	(208.9)
Balance, September 30, 2012	89,171	$ 1,316.5	1,820	$ 34.5	$ 20.9	$ 147.0	$ 1,518.9
Balance, December 31, 2010	75,545	$ 935.3	1,542	$ 15.1	$ (30.6)	$ 129.3	$ 1,049.1
Compensation on equity grants	11	1.2	-	-	-	-	1.2
Proceeds from equity offerings	9,200	298.0	188	6.3	-	-	304.3
Contributions from Targa Resources Corp.	-	7.9	-	1.2	-	-	9.1
Distributions to noncontrolling interests	-	-	-	-	-	(19.8)	(19.8)
Contributions from noncontrolling interests	-	-	-	-	-	-	-
Other comprehensive income	-	-	-	-	18.4	-	18.4
Net income	-	103.0	-	26.0	-	29.6	158.6
Distributions to unitholders	-	(142.0)	-	(23.9)	-	-	(165.9)
Balance, September 30, 2011	84,756	$ 1,203.4	1,730	$ 24.7	$ (12.2)	$ 139.1	$ 1,355.0

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30, 2012	2011
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 164.7	$ 158.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	13.6	6.7
Compensation on equity grants	2.6	1.2
Depreciation and amortization expense	142.1	132.2
Accretion of asset retirement obligations	2.9	2.7
Deferred income tax expense	1.2	0.6
Equity (earnings) losses, net of distributions	0.3	(1.4)
Risk management activities	3.8	(15.1)
Loss (gain) on sale or disposal of assets	15.5	(0.4)
Changes in operating assets and liabilities:		
Receivables and other assets	161.2	(82.9)
Inventory	4.9	(86.9)
Accounts payable and other liabilities	(197.3)	76.0
Net cash provided by operating activities	315.5	191.3
Cash flows from investing activities		
Outlays for property, plant and equipment	(364.8)	(211.4)
Business acquisitions	(25.8)	(164.2)
Investment in unconsolidated affiliate	(16.8)	(11.9)
Return of capital from unconsolidated affiliate	2.3	-
Other, net	1.6	0.3
Net cash used in investing activities	(403.5)	(387.2)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	720.0	1,426.0
Repayments of credit facility	(938.0)	(1,656.3)
Proceeds from issuance of senior notes	400.0	325.0
Cash paid on note exchange	-	(27.7)
Proceeds from equity offerings	168.3	304.3
Distributions to unitholders	(208.9)	(165.9)
Costs incurred in connection with financing arrangements	(4.5)	(6.2)
Contributions from parent	0.9	9.1
Contributions from noncontrolling interests	3.2	-
Distributions to noncontrolling interests	(19.7)	(19.8)
Net cash provided by financing activities	121.3	188.5
Net change in cash and cash equivalents	33.3	(7.4)
Cash and cash equivalents, beginning of period	55.6	76.3
Cash and cash equivalents, end of period	$ 88.9	$ 68.9

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

The year-end condensed balance sheet data was derived from audited financial statements, but does not include all disclosures required by GAAP. Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1 — Organization and Operations

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa Resources Corp. ("Targa" or "Parent"). Our common units, which represent limited partner interests in us, are listed on the NYSE under the symbol "NGLS." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries. In this Quarterly Report, unless the context requires otherwise, references to "Targa" are intended to mean Targa Resources Corp. together with its subsidiaries.

Targa Resources GP LLC is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa. As of September 30, 2012, Targa owns a 16.2% interest in us in the form of 1,819,817 general partner units and 12,945,659 common units. In addition, Targa Resources GP LLC owns incentive distribution rights ("IDRs"), which entitle it to receive increasing cash distributions up to 48% of distributable cash for a quarter.

Allocation of costs. The employees supporting our operations are employed by Targa Resources LLC, a Delaware limited liability company and an indirect wholly-owned subsidiary of Targa. Our financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa centralized general and administrative services and related administrative assets.

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil. See Note 11 for an analysis of our operations by segment.

Note 2 — Basis of Presentation

We have prepared these unaudited consolidated financial statements in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. While we derived the year-end balance sheet data from audited financial statements, this interim report does not include all disclosures required by GAAP for annual periods. These unaudited consolidated financial statements and other information included in this Quarterly Report should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report.

The unaudited consolidated financial statements for the three and nine months ended September 30, 2012 and 2011 include all adjustments which we believe are necessary for a fair presentation of the results for interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods have been reclassified to conform to the current year presentation.

Our financial results for the three and nine months ended September 30, 2012 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2012.

Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

The accounting policies that we follow are set forth in Note 3 of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2011. While there have been no significant changes to these policies during the nine months ended September 30, 2012, following is an expanded disclosure on how we calculate earnings per unit.

Earnings per unit. We account for earnings per unit ("EPU") in accordance with ASC 260 – Earnings per Share. Diluted EPU reflects the potential dilution that could occur if securities or other contracts to issue common units were exercised or converted into common units or resulted in the issuance of common units so long as it does not have an anti-dilutive effect on EPU. The dilutive effect is determined through the application of the treasury method. Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic EPU. For the nine months ended September 30, 2012, the dilutive effect of equity-settled performance units under our Long Term Incentive Plan did not have a material impact on our reported earnings per unit.

The limited partners' net income per unit is based on net income after allocation to the general partner's 2% interest and incentive distribution rights. Because our Partnership Agreement limits the quarterly distributions payable to holders of incentive distribution rights to a percentage of Available Cash (as defined in our Partnership Agreement), the calculation of the general partner's net income per unit does not reflect an incentive distribution on earnings in excess of the distributions declared for the period.

New Standards

Accounting Standards Update No. 2011-04, *Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*, was implemented in 2012. Note 9 – Fair Value Measurements includes additional disclosures regarding the fair value and fair value hierarchy classification of financial instruments reported at carrying value in our Consolidated Balance Sheets. Additionally, we have provided information regarding the unobservable inputs used in the fair value measurement of derivative contracts classified within Level 3 of the fair value hierarchy. The impact of Level 3 inputs on our financial statements is immaterial. Transfers among levels of the fair value hierarchy are deemed to occur at the end of the reporting period.

Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*, was retroactively adopted during 2012. We now display in the Consolidated Statements of Comprehensive Income (Loss) the tax effect of each component of other comprehensive income.

Note 4 — Property, Plant and Equipment

	September 30, 2012	December 31, 2011	Estimated useful lives (In years)
Natural gas gathering systems	$ 1,801.9	$ 1,740.6	5 to 20
Processing and fractionation facilities	1,111.3	1,062.7	5 to 25
Terminaling and storage facilities	402.4	380.7	5 to 25
Transportation assets	292.2	281.2	10 to 25
Other property, plant and equipment	57.9	54.9	3 to 25
Land	73.3	71.2	-
Construction in progress	423.0	195.6	-
	$ 4,162.0	$ 3,786.9	

Note 5 — Accounts Payable and Accrued Liabilities

The components of accounts payable and accrued liabilities consist of the following:

	September 30, 2012	December 31, 2011
Commodities	$ 336.2	$ 515.3
Other goods and services	91.2	86.3
Interest	26.4	32.3
Other	18.3	13.9
	$ 472.1	$ 647.8

Note 6 — Debt Obligations

	September 30, 2012	December 31, 2011
Senior secured revolving credit facility, variable rate, due July 2015 (1)(2)	$ 280.0	$ 498.0
Senior unsecured notes, 8¼% fixed rate, due July 2016 (1)	209.1	209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017	72.7	72.7
Unamortized discount	(2.6)	(2.9)
Senior unsecured notes, 7⅞% fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(31.1)	(32.8)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	400.0	-
	$ 1,661.7	$ 1,477.7
Letters of credit issued	$ 47.4	$ 92.5

(1) See Subsequent Events section of this note.
(2) As of September 30, 2012, availability under our $1.1 billion senior secured revolving credit facility was $772.6 million.

The following table shows the range of interest rates and the weighted average interest rate incurred on our variable-rate debt obligations during the nine months ended September 30, 2012:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	2.4% - 4.5%	2.6%

As of September 30, 2012, we were in compliance with the covenants contained in our various debt agreements.

6⅜% Senior Notes

On January 30, 2012, we privately placed $400.0 million in aggregate principal amount of 6⅜% Senior Notes due 2022 (the “6⅜% Notes”). The 6⅜% Notes resulted in approximately $395.5 million of net proceeds, which were used to reduce borrowings under our senior secured revolving credit facility and for general partnership purposes.

The 6⅜% Notes are unsecured senior obligations that rank pari passu in right of payment with existing and future senior indebtedness, including indebtedness under our credit facility. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by certain of our subsidiaries. The 6⅜% Notes are effectively subordinated to all secured indebtedness under our credit agreement, which is secured by substantially all of our assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the 6⅜% Notes accrues at the rate of 6⅜% per annum and is payable semi-annually in arrears on February 1 and August 1, commencing on August 1, 2012.

We may redeem 35% of the aggregate principal amount of the 6⅜% Notes at any time prior to February 1, 2015, with the net cash proceeds of one or more equity offerings. We must pay a redemption price of 106.375% 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 6⅜% Notes (excluding the 6⅜% Notes held by us) remains outstanding immediately after the occurrence of such redemption; and

2) the redemption occurs within 180 days of the date of the closing of such equity offering.

We may also redeem all or part of the 6⅜% Notes on or after February 1, 2017 at the prices set forth below plus accrued and unpaid interest and liquidated damages, if any, on the notes redeemed, if redeemed during the twelve month period beginning on February 1 of each year indicated below.

Year	Redemption Price
2017	103.188%
2018	102.125%
2019	101.063%
2020 and thereafter	100.000%

Subsequent Events

Revolving Credit Agreement

On October 3, 2012, we entered into a Second Amended and Restated Credit Agreement that amends and replaces our existing variable rate Senior Secured Credit Facility due July 2015 (the "Previous Revolver") to provide a variable rate Senior Secured Credit Facility due October 3, 2017 (the "TRP Revolver"). The TRP Revolver increases available commitments to $1.2 billion from $1.1 billion and allows us to request up to an additional $300.0 million in commitment increases.

We incurred a $1.7 million loss related to a partial write-off of debt issue costs associated with the Previous Revolver as a result of a change in syndicate members under the new TRP Revolver. The remaining deferred debt issue costs, along with the issue costs associated with the October 2012 amendment, will be amortized on a straight-line basis over the life of the TRP Revolver.

The TRP Revolver bears interest, at our option, at either (a) a base rate equal to the highest of (i) Bank of America's prime rate, (ii) the federal funds rate plus 0.5% or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 0.75% to 1.75%, or (b) LIBOR plus an applicable margin ranging from 1.75% to 2.75%.

We are required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% times the actual daily average unused portion of the TRP Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable rate from 1.75% to 2.75%.

The TRP Revolver is collateralized by a majority of our assets. Borrowings are guaranteed by our restricted subsidiaries.

The TRP Revolver restricts our ability to make distributions of available cash to unitholders if a default or an event of default (as defined in the TRP Revolver) exists or would result from such distribution. The TRP Revolver requires us to maintain a ratio of consolidated funded indebtedness to consolidated adjusted EBITDA of no more than 5.50 to 1.00. The TRP Revolver also requires us to maintain a ratio of consolidated EBITDA to consolidated interest expense of no less than 2.25 to 1.00. In addition, the TRP Revolver contains various covenants that may limit, among other things, our ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates (in each case, subject to our right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing).

8¼% Senior Notes

On October 19, 2012, we issued a call notice for full redemption of our 8¼% Senior Unsecured Notes due July 2016, (the "8¼% Notes"), at a redemption price of 104.125% plus accrued interest through the redemption date of November 19, 2012. As of September 30, 2012, the outstanding balance on the 8¼% Notes was $209.1 million. The redemption will result in a premium paid on the redemption of $8.6 million and a write-off of $2.6 million of unamortized debt issue costs.

5¼% Senior Notes

On October 25, 2012, we privately placed $400.0 million in aggregate principal amount of 5¼% Senior Unsecured Notes due May 2023 (the "5¼% Notes") at 99.5% of par value. The 5¼% Notes resulted in approximately $398.0 million of gross proceeds ($393.5 million of net proceeds), which will be used to redeem our 8¼% Notes, reduce borrowings under the TRP Revolver and for general partnership purposes.

Note 7 — Partnership Units and Related Matters

Public Offerings of Common Units

On January 23, 2012, we completed a public offering of 4,000,000 common units at a price of $38.30 per common unit ($37.11 per common unit, net of underwriting discounts). Net proceeds from this offering were approximately $149.9 million. Pursuant to the exercise of the underwriters' overallotment option, we issued an additional 405,000 common units, providing net proceeds of approximately $15.0 million. As part of this offering, Targa purchased 1,300,000 common units with an aggregate value of $49.8 million (based on the offering price of $38.30). The units purchased by Targa were not subject to any underwriter discounts or commissions. In addition, Targa contributed $3.4 million to us for 89,898 general partner units to maintain its 2% general partner interest in us. We used the net proceeds from this offering for general partnership purposes, including the repayment of indebtedness.

In August 24, 2012, we entered into an Equity Distribution Agreement ("EDA") with Citigroup Global Markets Inc. ("Citibank") which permits us to sell, at our option, up to an aggregate of $100 million of our common units through Citibank, as sales agent. Settlement for sales of common units will occur on the third business day following the date on which any sales were made in return for payment of the net proceeds to us. During the quarter ended September 30, 2012, there were no sales of common units pursuant to this program.

Distributions

The following table details the distributions declared and/or paid during the first nine months of 2012:

		Distributions				
			General Partner			
Three Months Ended	**Date Paid or to be Paid**	**Limited Partners Common**	**Incentive**	**2%**	**Total**	**Distributions per limited partner unit**
		(In millions, except per unit amounts)				
September 30, 2012	November 14, 2012	$ 59.1	$ 16.1	$ 1.5	$ 76.7	$ 0.6625
June 30, 2012	August 14, 2012	57.3	14.4	1.5	73.2	0.6425
March 31, 2012	May 15, 2012	55.5	12.7	1.4	69.6	0.6225
December 31, 2011	February 14, 2012	53.7	11.0	1.3	66.0	0.6025

Note 8 — Derivative Instruments and Hedging Activities

Commodity Hedges

The primary purpose of our commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations through 2015 and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations as well as in the LOU portion of the Coastal Gathering and Processing Operations through 2014 that result from its percent of proceeds processing arrangement by entering into derivative instruments including swaps and purchased puts (floors) and calls (caps). We have designated these derivative contracts as cash flow hedges.

The hedges generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition. We believe this approach avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. Our natural gas and NGL hedges are settled using published index prices for delivery at various locations which closely approximate our actual natural gas and NGL delivery points.

We hedge a portion of our condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This necessarily exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying West Texas condensate equity volumes.

At September 30, 2012, the notional volumes of our commodity hedges for our equity volumes were:

Commodity	Instrument	Unit	2012	2013	2014	2015
Natural Gas	Swaps	MMBtu/d	31,790	26,089	18,000	4,500
NGL	Swaps	Bbl/d	9,361	5,650	1,000	-
NGL	Puts (propane)	Bbl/d	294	-	-	-
NGL	Calls (ethane) (1)	Bbl/d	2,000	-	-	-
Condensate	Swaps	Bbl/d	1,660	1,795	700	-

(1) Utilized in connection with 2,000 Bbl/d of 2012 ethane swaps providing a floor on ethane with upside.

We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and we record changes in fair value and cash settlements to revenues.

The following schedules reflect the fair values of our derivative instruments:

	Derivative Assets			Derivative Liabilities		
		Fair Value as of			Fair Value as of	
	Balance Sheet Location	September 30, 2012	December 31, 2011	Balance Sheet Location	September 30, 2012	December 31, 2011
Derivatives designated as hedging instruments						
Commodity contracts	Current assets	$ 33.4	$ 40.3	Current liabilities	$ 5.9	$ 40.6
	Long-term assets	11.0	10.9	Long-term liabilities	7.2	15.8
Total derivatives designated as hedging instruments		$ 44.4	$ 51.2		$ 13.1	$ 56.4
Derivatives not designated as hedging instruments						
Commodity contracts	Current assets	$ 0.3	$ 0.7	Current liabilities	$ 0.1	$ 0.5
	Long-term assets	0.1	-	Long-term liabilities	-	-
Total derivatives not designated as hedging instruments		$ 0.4	$ 0.7		$ 0.1	$ 0.5
Total derivatives		$ 44.8	$ 51.9		$ 13.2	$ 56.9

The fair value of our 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.

The estimated fair value of our derivative instruments was a net asset of $31.6 million as of September 30, 2012, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. These default probabilities have been applied to the unadjusted fair values of the derivative instruments to arrive at the credit risk adjustment, which was immaterial for all periods presented.

Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas, NGL and crude oil 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.

The following tables reflect amounts recorded in other comprehensive income ("OCI") and amounts reclassified from OCI to revenue and expense for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Interest rate contracts	$ -	$ (2.3)	$ -	$ (4.3)
Commodity contracts	(22.5)	47.0	70.4	(9.7)
	$ (22.5)	$ 44.7	$ 70.4	$ (14.0)

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
Location of Gain (Loss)	2012	2011	2012	2011
Interest expense, net	$ (1.9)	$ (1.0)	$ (6.1)	$ (5.7)
Revenues	14.8	(10.3)	30.0	(26.7)
	$ 12.9	$ (11.3)	$ 23.9	$ (32.4)

Hedge ineffectiveness was immaterial for all periods presented.

Our consolidated earnings are also affected by the use of the mark-to-market method of accounting for derivative instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. We recorded the following mark-to-market gains (losses) for the periods indicated:

		Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized on Income on Derivatives	2012	2011	2012	2011
Commodity contracts	Revenue	$ (0.1)	$ 0.4	$ 0.9	$ 1.4
Interest Rate Swaps	Other income (expense)	-	(1.8)	-	(5.0)

The following table shows the deferred gains (losses) included in accumulated OCI that will be reclassified into earnings through the end of 2015:

	September 30, 2012	December 31, 2011
Commodity hedges	$ 31.0	$ (9.4)
Interest rate hedges	(10.3)	(16.4)

As of September 30, 2012, deferred net gains of $26.8 million on commodity hedges and deferred net losses of $6.5 million on terminated interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

See Note 9 for additional disclosures related to derivative instruments and hedging activities.

Note 9 — Fair Value Measurements

Under generally accepted accounting principles, our consolidated balance sheet reflects a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments are reported at fair value in our consolidated balance sheet. Other financial instruments are reported at historical cost or amortized cost in our consolidated balance sheet, with fair value measurements for these instruments provided as supplemental information.

Following is additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swap and option contracts and fixed price commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. 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.

The fair values of our derivative instruments, which aggregate to a net asset position of $31.6 million as of September 30, 2012, are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This asset position reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net asset of $1.9 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $61.3 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. As such, long-term debt is primarily the other financial instrument for which our carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- senior secured revolving credit facility is based on carrying value which approximates fair value as its interest rate is based on prevailing market rates;

- senior unsecured notes are based on quoted market prices derived from trades of the debt.

Fair Value Hierarchy

We categorize the inputs to the fair value measurements using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;

- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and

- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

The following table shows a breakdown by fair value hierarchy category for (1) financial instruments measurements included in our consolidated balance sheet at fair value and (2) supplemental fair value disclosures for other financial instruments.

	September 30, 2012				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$ 44.8	$ 44.8	$ -	$ 44.7	$ 0.1
Liabilities from commodity derivative contracts	13.2	13.2	-	12.4	0.8
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	88.9	88.9			
Senior secured revolving credit facility	280.0	280.0	-	280.0	-
Senior unsecured notes	1,381.7	1,526.6	-	1,526.6	-

	December 31, 2011				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$ 51.9	$ 51.9	$ -	$ 51.9	$ -
Liabilities from commodity derivative contracts	56.9	56.9	-	56.9	-
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	55.6	55.6			
Senior secured revolving credit facility	498.0	498.0	-	498.0	-
Senior unsecured notes	979.7	1,057.3	-	1,057.3	-

Additional Information Regarding Level 3 Fair Value Measurements

As of September 30, 2012, we reported certain of our natural gas basis swaps at fair value using Level 3 inputs due to such derivatives not having observable market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

The fair value of these natural gas basis swaps is determined using a discounted cash flow valuation technique based on a forward commodity basis curve. For these derivatives, the primary input to the valuation model is the forward commodity basis curve which is based on observable or public data sources and extrapolated when observable prices are not available.

As of September 30, 2012, we have two natural gas basis swaps categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are the forward natural gas basis curve beginning in year 2015, and the forward natural gas basis curve for the South Texas Natural Gas Pipeline beginning in November 2012. Because a significant portion of the derivative’s term is in 2015 and beyond, for the former, and in November 2012, for the latter, both valuations are categorized as Level 3. The change in the fair value of our Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

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
Balance, December 31, 2011	$ -
Loss (gain) included in Revenue	(0.1)
Unrealized losses included in OCI	0.8
Balance, September 30, 2012	$ 0.7

The amount of gains for the period included in earnings is attributable to the change in unrealized gains related to assets or liabilities held at the reporting date. There have been no transfers of assets or liabilities between the three levels of the fair value hierarchy during the nine months ended September 30, 2012.

Note 10 — Commitments and Contingencies

Environmental

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Environmental reserves do not reflect management's assessment of any 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.

Environmental liabilities were not significant as of September 30, 2012.

Targa has reimbursed us for maintenance capital expenditures of $16.7 million as of September 30, 2012, which are required to be made in connection with a settlement agreement with the New Mexico Environment Department relating to air emissions at three gas processing plants operated by our Versado Gas Processors, LLC joint venture, with $0.9 million reimbursed to us during the nine months ended September 30, 2012. These capital projects were substantially complete as of September 30, 2012.

Legal Proceedings

We are a party to various legal proceedings and/or regulatory proceedings and certain claims, suits and complaints arising in the ordinary course of business that have been filed or are pending against us. We believe all such matters are without merit or involve amounts which, if resolved unfavorably, would not have a material effect on our financial position, results of operations, or cash flows.

Note 11 — Segment Information

We report our operations in two divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of our hedging activities are reported in Other.

Our Natural Gas Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, transporting, distributing and marketing of NGLs, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations.

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to, and supplied in part by, our Natural Gas Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities.

Our Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing our own NGL production and purchasing NGL products in selected United States markets; (2) providing LPG balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users; and (4) marketing natural gas available to us from our Natural Gas Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results of our commodity hedging activities included in operating margin. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column.

Our reportable segment information is shown in the following tables:

	Three Months Ended September 30, 2012						
	Field Gathering and Processing	**Coastal Gathering and Processing**	**Logistics Assets**	**Marketing and Distribution**	**Other**	**Corporate and Eliminations**	**Total**
Revenues							
Sales of commodities	$ 42.2	$ 60.5	$ 52.9	$ 1,136.4	$ 14.0	$ -	$ 1,306.0
Fees from midstream services	8.5	7.4	43.6	27.4	-	-	86.9
	50.7	67.9	96.5	1,163.8	14.0	-	1,392.9
Intersegment revenues							
Sales of commodities	274.8	150.5	0.5	151.5	-	(577.3)	-
Fees from midstream services	0.3	-	27.6	7.2	-	(35.1)	-
	275.1	150.5	28.1	158.7	-	(612.4)	-
Revenues	$ 325.8	$ 218.4	$ 124.6	$ 1,322.5	$ 14.0	$ (612.4)	$ 1,392.9
Operating margin	$ 53.8	$ 18.0	$ 50.4	$ 25.4	$ 14.0	$ -	$ 161.6
Other financial information:							
Total assets (1)	$ 1,717.3	$ 421.8	$ 977.5	$ 491.7	$ 44.8	$ 117.8	$ 3,770.9
Capital expenditures	$ 66.7	$ 28.2	$ 64.0	$ 0.9	$ -	$ 1.7	$ 161.5

(1) We recorded a $15.4 million loss in Other Operating (Income) Expense due to a write-off of our investment in the Yscloskey joint venture interest processing plant in Southern Louisiana included in the Coastal Gathering and Processing segment. Following Hurricane Isaac, the joint venture owners elected not to restart the plant.

	Three Months Ended September 30, 2011						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 47.9	$ 75.2	$ -	$ 1,530.3	$ (10.8)	$ 0.1	$ 1,642.7
Fees from midstream services	6.8	3.9	35.8	23.5	-	-	70.0
	54.7	79.1	35.8	1,553.8	(10.8)	0.1	1,712.7
Intersegment revenues							
Sales of commodities	385.4	242.9	0.1	186.0	-	(814.4)	-
Fees from midstream services	0.2	-	21.6	8.8	-	(30.6)	-
	385.6	242.9	21.7	194.8	-	(845.0)	-
Revenues	$ 440.3	$ 322.0	$ 57.5	$ 1,748.6	$ (10.8)	$ (844.9)	$ 1,712.7
Operating margin	$ 71.8	$ 39.8	$ 30.1	$ 19.7	$ (10.8)	$ 0.1	$ 150.7
Other financial information:							
Total assets	$ 1,647.3	$ 425.2	$ 713.2	$ 702.3	$ 56.0	$ 78.0	$ 3,622.0
Capital expenditures	$ 40.2	$ 4.2	$ 165.0	$ 0.6	$ -	$ 0.8	$ 210.8

	Nine Months Ended September 30, 2012						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 134.2	$ 172.0	$ 152.9	$ 3,622.2	$ 28.1	$ -	$ 4,109.4
Fees from midstream services	27.3	15.9	125.6	78.5	-	0.1	247.4
	161.5	187.9	278.5	3,700.7	28.1	0.1	4,356.8
Intersegment revenues							
Sales of commodities	851.9	532.7	0.6	398.3	-	(1,783.5)	-
Fees from midstream services	0.9	0.1	76.2	23.5	-	(100.7)	-
	852.8	532.8	76.8	421.8	-	(1,884.2)	-
Revenues	$ 1,014.3	$ 720.7	$ 355.3	$ 4,122.5	$ 28.1	$ (1,884.1)	$ 4,356.8
Operating margin	$ 180.6	$ 92.3	$ 139.2	$ 77.8	$ 28.1	$ -	$ 518.0
Other financial information:							
Total assets (1)	$ 1,717.3	$ 421.8	$ 977.5	$ 491.7	$ 44.8	$ 117.8	$ 3,770.9
Capital expenditures	$ 139.6	$ 32.8	$ 213.8	$ 10.4	$ -	$ 3.2	$ 399.8

(1) We recorded a $15.4 million loss in Other Operating (Income) Expense during the three months ended September 30, 2012 due to a write-off of our investment in the Yscloskey joint venture interest processing plant in Southern Louisiana included in our Coastal Gathering and Processing segment. Following Hurricane Isaac, the joint venture owners elected not to restart the plant.

	Nine Months Ended September 30, 2011						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 145.3	$ 243.9	$ 0.1	$ 4,505.5	$ (28.4)	$ -	$ 4,866.4
Fees from midstream services	19.6	13.4	92.1	62.1	-	0.2	187.4
	164.9	257.3	92.2	4,567.6	(28.4)	0.2	5,053.8
Intersegment revenues							
Sales of commodities	1,051.8	704.9	0.4	465.9	-	(2,223.0)	-
Fees from midstream services	0.7	0.4	64.4	25.7	-	(91.2)	-
	1,052.5	705.3	64.8	491.6	-	(2,314.2)	-
Revenues	$ 1,217.4	$ 962.6	$ 157.0	$ 5,059.2	$ (28.4)	$ (2,314.0)	$ 5,053.8
Operating margin	$ 213.0	$ 121.8	$ 85.9	$ 82.8	$ (28.4)	$ 0.1	$ 475.2
Other financial information:							
Total assets	$ 1,647.3	$ 425.2	$ 713.2	$ 702.3	$ 56.0	$ 78.0	$ 3,622.0
Capital expenditures	$ 112.0	$ 9.8	$ 252.6	$ 1.5	$ -	$ 1.4	$ 377.3

The following table shows our consolidated revenues by product and service for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Sales of commodities				
Natural gas sales	$ 252.1	$ 304.6	$ 642.7	$ 846.2
NGL sales	957.4	1,323.4	3,198.4	3,969.1
Condensate sales	29.0	25.7	87.0	80.3
Petroleum products	52.7	-	152.5	-
Derivative activities	14.8	(11.0)	28.8	(29.2)
	1,306.0	1,642.7	4,109.4	4,866.4
Fees from midstream services				
Fractionating and treating fees	28.6	25.7	84.0	60.1
Storage, terminaling, transportation and export fees	41.6	27.9	107.4	77.3
Gas processing fees	11.8	8.3	30.1	23.1
Other	4.9	8.1	25.9	26.9
	86.9	70.0	247.4	187.4
Total revenues	$ 1,392.9	$ 1,712.7	$ 4,356.8	$ 5,053.8

The following table shows a reconciliation of operating margin to net income for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Reconciliation of operating margin to net income:				
Operating margin	$ 161.6	$ 150.7	$ 518.0	$ 475.2
Depreciation and amortization expense	(47.9)	(45.0)	(142.1)	(132.2)
General and administrative expense	(33.5)	(33.7)	(100.0)	(98.6)
Interest expense, net	(29.0)	(25.7)	(87.8)	(80.4)
Income tax expense	(0.9)	(1.5)	(2.7)	(5.2)
Other, net	(22.2)	0.1	(20.7)	(0.2)
Net income	$ 28.1	$ 44.9	$ 164.7	$ 158.6

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2011 ("Annual Report"), as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October, 2006 by Targa Resources Corp. ("Targa" or "Parent"). Our common units are listed on the NYSE under the symbol "NGLS." In this report, unless the context requires otherwise, references to "we," "us," or "our" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Targa Resources GP LLC (the "General Partner") is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly-owned subsidiary of Targa.

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil.

We report our operations in two divisions: (i) Natural Gas Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The financial results of our hedging activities are reported in Other.

Our Natural Gas Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert raw NGLs into NGL products and provides certain value added services such as storing, terminaling, transporting, distributing and marketing of NGLs, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations.

The Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to and supplied, in part, by our Natural Gas Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities.

The Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing our own NGL production and purchasing NGL products in selected United States markets; (2) providing LPG balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users; and (4) marketing natural gas available to us from our Natural Gas Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results of commodity hedging activities included in operating margin.

2012 Developments

In January 2012, we completed an equity offering of 4,405,000 common units and a $400 million senior notes offering, resulting in $563.9 million of combined net proceeds. As part of the equity offering, a wholly owned subsidiary of Targa purchased 1,300,000 common units. We used the net proceeds from these offerings for general partnership purposes and the repayment of indebtedness. See "—Cash Flow from Financing Activities".

In July 2012, we filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $300 million of debt or equity securities (the "2012 Shelf").

In July 2012, we acquired the Big Lake gas processing plant in Lake Charles, Louisiana. The transaction was paid entirely with cash funded through borrowings under our senior secured revolving credit facility.

In August 2012, we entered into an Equity Distribution Agreement ("EDA") with Citigroup Global Markets Inc. ("Citibank") pursuant to which we may sell, at our option, up to an aggregate of $100 million of our common units through Citibank, as sales agent. Settlement for sales of common units will occur on the third business day following the date on which any sales were made in return for payment of the net proceeds to us. During the quarter ended September 30, 2012, there were no sales of common units pursuant to this program.

Subsequent Events

On October 3, 2012, we entered into a Second Amended and Restated Credit Agreement that amends and replaces our existing variable rate Senior Secured Credit Facility due July 2015 (the "Previous Revolver") to provide a variable rate Senior Secured Credit Facility due October 3, 2017 (the "TRP Revolver"). The TRP Revolver increases available commitments to $1.2 billion from $1.1 billion and allows us to request up to an additional $300.0 million in commitment increases.

We incurred a $1.7 million loss related to a partial write-off of debt issue costs associated with the Previous Revolver as a result of a change in syndicate members under the new TRP Revolver. The remaining deferred debt issue costs, along with the issue costs associated with the October 2012 amendment, will be amortized on a straight-line basis over the life of the TRP Revolver.

On October 19, 2012, we issued a call notice for full redemption of our 8¼% Senior Unsecured Notes due July 2016, (the "8¼% Notes"), at a redemption price of 104.125% plus accrued interest through the redemption date of November 19, 2012. As of September 30, 2012, the outstanding balance on the 8¼% Notes was $209.1 million. The redemption will result in a premium paid on the redemption of $8.6 million and a write-off of $2.6 million of unamortized debt issue costs.

On October 25, 2012, we privately placed $400.0 million in aggregate principal amount of 5¼% Senior Unsecured Notes due May 2023 (the "5¼% Notes") at 99.5% of par value. The 5¼% Notes resulted in approximately $398.0 million of gross proceeds ($393.5 million of net proceeds), which will be used to redeem our 8¼% Notes, reduce borrowings under the TRP Revolver and for general partnership purposes.

New Standards

Accounting Standards Update No. 2011-04, *Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS*, was implemented in 2012. We have made additional disclosures in Note 9 – Fair Value Measurements to report the fair value of financial instruments reported at carrying value on our Consolidated Balance Sheets and their classification in the fair value hierarchy. Additionally, we have provided information regarding the unobservable inputs used in the fair value measurement of derivative contracts classified as Level 3 within the fair value hierarchy. The impact of Level 3 inputs on our financial statements is immaterial to both net assets and other comprehensive income, and there is no impact whatsoever to net income or cash flows. It is our policy that transfers among levels of the fair value hierarchy are deemed to occur at the end of the reporting period.

Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income*, was implemented during 2012. We have made new disclosures this year, applied retroactively to prior periods, in the Consolidated Statements of Comprehensive Income (Loss) to report the tax effect of each component of other comprehensive income.

How We Evaluate Our Operations

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

Our profitability is also impacted by fee-based revenues. Our growth strategy, largely based on expansion of our existing facilities as well as third-party acquisitions of businesses and assets, includes an increasing percentage of assets that generate fee-based revenues. Fixed fees for services such as fractionation, storage and terminaling are not directly tied to changes in market prices for commodities.

Management uses a variety of financial measures and operational measurements to analyze our performance. These include: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating expenses and (3) the following non-GAAP measures — gross margin, operating margin, adjusted EBITDA and distributable cash flow.

Throughput Volumes, Facility Efficiencies and Fuel Consumption. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from oil and gas wells that are connected to our gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production, as well as by capturing natural gas supplies currently gathered by third parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to our Downstream Business' fractionation facilities. We fractionate NGLs generated by our gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities.

In addition, we seek to increase operating margin by limiting volume losses, reducing fuel consumption and by increasing efficiency. With our gathering systems' extensive use of remote monitoring capabilities, we monitor the volumes of natural gas received at the wellhead or central delivery points along our gathering systems, the volume of natural gas received at our processing plant inlets and the volumes of NGLs and residue natural gas recovered by our processing plants. We also monitor the volumes of NGLs received, stored, fractionated and delivered across our logistics assets. This information is tracked through our processing plants and Downstream Business facilities to determine customer settlements for sales and volume related fees for service and helps us increase efficiency and reduce fuel consumption.

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

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

Gross Margin. We define gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as by our contract mix and hedging program. We define Natural Gas Gathering and Processing gross margin as total operating revenues from the sale of natural gas and NGLs plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees and NGL sales, less cost of sales, which consists primarily of NGL purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin. Operating margin is an important performance measure of the core profitability of our operations. We define operating margin as gross margin less operating expenses.

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definition of gross margin and operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Management reviews business segment gross margin and operating margin monthly as a core internal management process. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Gross margin and operating margin provide useful information to investors because they are used as supplemental financial measures by us and by external users of our financial statements, including investors and commercial banks, to assess:

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

Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Adjusted EBITDA. We define Adjusted EBITDA as net income before: interest; income taxes; depreciation and amortization; gains or losses on debt repurchases and asset disposals; and non-cash risk management activities related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others.

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

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

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

Distributable Cash Flow. We define distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash losses (gains) on mark-to-market derivative contracts, debt repurchases and asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests.

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

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

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

Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measures used by management to the most directly comparable GAAP measures for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	**2011**	**2012**	**2011**
Reconciliation of gross margin and operating margin to net income:		**(In millions)**		
Gross margin	$ 239.9	$ 227.2	$ 745.1	$ 689.3
Operating expenses	(78.3)	(76.5)	(227.1)	(214.1)
Operating margin	161.6	150.7	518.0	475.2
Depreciation and amortization expenses	(47.9)	(45.0)	(142.1)	(132.2)
General and administrative expenses	(33.5)	(33.7)	(100.0)	(98.6)
Interest expense, net	(29.0)	(25.7)	(87.8)	(80.4)
Income tax expense	(0.9)	(1.5)	(2.7)	(5.2)
Gain (loss) on sale or disposal of assets	(18.9)	0.3	(18.8)	0.4
Other, net	(3.3)	(0.2)	(1.9)	(0.6)
Net income	$ 28.1	$ 44.9	$ 164.7	$ 158.6

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Reconciliation of net cash provided by operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$ 90.5	$ (61.3)	$ 315.5	$ 191.3
Net income attributable to noncontrolling interests	(3.9)	(9.0)	(23.5)	(29.6)
Interest expense, net (1)	24.5	24.7	74.2	73.7
Current income tax expense	0.5	2.4	1.5	4.6
Other (2)	(5.3)	18.8	(14.5)	10.8
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	42.6	105.4	(166.1)	169.8
Accounts payable and other liabilities	(32.7)	26.3	197.3	(76.0)
Adjusted EBITDA	$ 116.2	$ 107.3	$ 384.4	$ 344.6

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $4.5 million and $13.6 million for the three and nine months ended September 30, 2012, and $1.0 million and $6.7 million for the three and nine months ended September 30, 2011.

(2) Includes equity earnings (loss) from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations, amortization of stock based compensation and loss on sale or disposal of assets.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$ 24.2	$ 35.9	$ 141.2	$ 129.0
Add:				
Interest expense, net	29.0	25.7	87.8	80.4
Income tax expense	0.9	1.5	2.7	5.2
Depreciation and amortization expenses	47.9	45.0	142.1	132.2
Loss on sale or disposal of assets	15.6	-	15.5	-
Risk management activities	1.6	2.0	3.8	6.0
Noncontrolling interests adjustment (1)	(3.0)	(2.8)	(8.7)	(8.2)
Adjusted EBITDA	$ 116.2	$ 107.3	$ 384.4	$ 344.6

(1) Noncontrolling interest portion of depreciation and amortization expenses.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to distributable cash flow:				
Net income attributable to Targa Resources Partners LP	$ 24.2	$ 35.9	$ 141.2	$ 129.0
Depreciation and amortization expenses	47.9	45.0	142.1	132.2
Deferred income tax expense	0.4	(0.9)	1.2	0.6
Amortization in interest expense	4.5	2.5	13.6	8.1
Loss on sale or disposal of assets	15.6	-	15.5	-
Risk management activities	1.6	2.0	3.8	6.0
Maintenance capital expenditures	(16.2)	(24.7)	(48.0)	(57.2)
Other (1)	(0.8)	5.6	(1.8)	10.8
Targa Resources Partners LP distributable cash flow	$ 77.2	$ 65.4	$ 267.6	$ 229.5

(1) Includes reimbursements of certain environmental maintenance capital expenditures by Targa and the noncontrolling interest portion of maintenance capital expenditures, depreciation and amortization expenses.

Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2012 and 2011 (in millions, except operating statistics and price amounts):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
Revenues	$ 1,392.9	$ 1,712.7	$ (319.8)	(19%)	$ 4,356.8	$ 5,053.8	$ (697.0)	(14%)
Product purchases	1,153.0	1,485.5	(332.5)	(22%)	3,611.7	4,364.5	(752.8)	(17%)
Gross margin (1)	239.9	227.2	12.7	6%	745.1	689.3	55.8	8%
Operating expenses	78.3	76.5	1.8	2%	227.1	214.1	13.0	6%
Operating margin (2)	161.6	150.7	10.9	7%	518.0	475.2	42.8	9%
Depreciation and amortization expenses	47.9	45.0	2.9	6%	142.1	132.2	9.9	7%
General and administrative expenses	33.5	33.7	(0.2)	(1%)	100.0	98.6	1.4	1%
Other operating (income) expense	18.9	(0.3)	19.2	nm	18.8	(0.4)	19.2	nm
Income from operations	61.3	72.3	(11.0)	(15%)	257.1	244.8	12.3	5%
Interest expense, net	(29.0)	(25.7)	(3.3)	13%	(87.8)	(80.4)	(7.4)	9%
Equity earnings (loss)	(2.2)	2.2	(4.4)	(200%)	(0.3)	5.2	(5.5)	(106%)
Loss on mark-to-market derivative instruments	-	(1.8)	1.8	100%	-	(5.0)	5.0	100%
Other	(1.1)	(0.6)	(0.5)	(83%)	(1.6)	(0.8)	(0.8)	(100%)
Income tax expense	(0.9)	(1.5)	0.6	40%	(2.7)	(5.2)	2.5	48%
Net income	28.1	44.9	(16.8)	(37%)	164.7	158.6	6.1	4%
Less: Net income attributable to noncontrolling interests	3.9	9.0	(5.1)	(57%)	23.5	29.6	(6.1)	(21%)
Net income attributable to Targa Resources Partners LP	$ 24.2	$ 35.9	$ (11.7)	(33%)	$ 141.2	$ 129.0	$ 12.2	9%
Financial and operating data:								
Financial data:								
Adjusted EBITDA (3)	$ 116.2	$ 107.3	$ 8.9	8%	$ 384.4	$ 344.6	$ 39.8	12%
Distributable cash flow (4)	77.2	65.4	11.8	18%	267.6	229.5	38.1	17%
Operating data:								
Plant natural gas inlet, MMcf/d (5)(6)	1,968.6	2,087.0	(118.4)	(6%)	2,094.3	2,152.8	(58.5)	(3%)
Gross NGL production, MBbl/d	123.4	121.4	2.0	2%	126.6	122.2	4.4	4%
Natural gas sales, BBtu/d (6)	981.8	799.7	182.1	23%	924.4	746.6	177.8	24%
NGL sales, MBbl/d	282.0	258.9	23.1	9%	277.1	265.1	12.0	5%
Condensate sales, MBbl/d	3.6	3.2	0.4	13%	3.5	3.2	0.3	9%

(1) Gross margin is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."
(2) Operating margin is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."
(3) Adjusted EBITDA is net income before: interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and asset disposals, and non-cash risk management activities related to derivative instruments. This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."
(4) Distributable cash flow is income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash losses (gains) on mark-to-market derivative contracts, debt repurchases and asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs). This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."
(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Revenues, including the impacts of hedging, decreased due to the impact of lower realized prices on commodities ($579.8 million), partially offset by higher commodity sales volumes ($190.4 million), petroleum product revenues ($52.7 million), and higher fee-based and other revenues ($16.9 million).

The increase in operating margin reflects a higher gross margin, partially offset by higher operating expenses. The increase in gross margin resulted from higher volumes and fee revenues more than offset by lower realized sales prices and lower product purchase costs due to the weaker commodity price environment. The increase in our operating costs was primarily due to our expansion and acquisition activities. See "—Results of Operations – By Reportable Segment" for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the impact of new assets placed in service as well as assets associated with business acquisitions.

General and administrative expenses were flat.

Other operating (income) expense reflects a $15.4 million loss due to a write-off of our investment in the Yscloskey joint interest processing plant in Southeastern Louisiana. Following Hurricane Isaac, the joint venture owners elected not to restart the plant. Additionally, other operating (income) expense includes $3.3 million in costs associated with the clean-up and repairs necessitated by Hurricane Isaac at our Coastal Straddle plants.

The increase in interest expense was the result of higher borrowings ($4.7 million) and higher effective interest rate ($1.7 million), offset by higher capitalized interest ($3.1 million) attributable to our expansion capital expenditures.

Operations at our non-operated equity investment, Gulf Coast Fractionators ("GCF"), continued to be impacted by the planned shutdown of operations that started during the second quarter and was completed in the third quarter associated with GCF's 43 MBbl/d capacity expansion. The facility's operations were also hampered by start-up issues associated with the expansion. This resulted in a loss for the quarter from this equity investment.

The mark-to-market loss in 2011 was attributable to interest rate swaps that were de-designated during the second quarter of that year. Consequently, we discontinued hedge accounting on those swaps, so changes in fair value and cash settlements were recorded as mark-to-market loss. We terminated all of our interest rate swaps in September 2011.

The decrease in net income attributable to noncontrolling interests reflects the impact of the weaker price environment on Versado and Venice, as well as the disruption of operations at Venice due to Hurricane Isaac.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

Revenues, including the impacts of hedging, decreased due to the impact of lower realized prices on commodities ($1,318.2 million), partially offset by higher commodity sales volumes ($409.9 million), petroleum product revenues ($152.5 million), and higher fee-based and other revenues ($58.8 million).

The increase in operating margin reflects a higher gross margin, partially offset by higher operating expenses. The increase in gross margin resulted from higher volumes and fee revenues more than offset by lower realized sales prices and lower product purchase costs due to the weaker commodity price environment. The increase in our operating costs was primarily due to our expansion and acquisition activities. See "—Results of Operations – By Reportable Segment" for additional information regarding changes in the components of operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the impact of new assets placed in service as well as assets associated with business acquisitions.

General and administrative expenses were flat.

Other operating (income) expense relates to the Yscloskey plant closure and Hurricane Isaac repair costs as discussed above.

The increase in interest expense was the result of higher borrowings ($8.6 million) and higher effective interest rate ($5.2 million), offset by higher capitalized interest ($6.4 million) attributable to our expansion capital expenditures.

Operations at our non-operated equity investment, Gulf Coast Fractionators, variance is explained above. This resulted in a loss for 2012 from this equity investment.

Mark-to-market loss variance is explained above.

The decrease in net income attributable to noncontrolling interests reflects the impact of the weaker price environment on Versado and Venice, as well as the disruption of operations at Venice due to Hurricane Isaac.

Results of Operations—By Reportable Segment

Our operating margin by reportable segment is:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
				(In millions)			
Three Months Ended:							
September 30, 2012	$ 53.8	$ 18.0	$ 50.4	$ 25.4	$ 14.0	$ -	$ 161.6
September 30, 2011	71.8	39.8	30.1	19.7	(10.8)	0.1	150.7
Nine Months Ended:							
September 30, 2012	180.6	92.3	139.2	77.8	28.1	-	518.0
September 30, 2011	213.0	121.8	85.9	82.8	(28.4)	0.1	475.2

Natural Gas Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended September 30,		2012 vs. 2011		Nine Months Ended September 30,		2012 vs. 2011	
	2012	2011			2012	2011		
	($ in millions)							
Gross margin	$ 84.0	$ 102.4	$ (18.4)	(18%)	$ 271.2	$ 299.3	$ (28.1)	(9%)
Operating expenses	30.2	30.6	(0.4)	(1%)	90.6	86.3	4.3	5%
Operating margin	$ 53.8	$ 71.8	$ (18.0)	(25%)	$ 180.6	$ 213.0	$ (32.4)	(15%)
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Sand Hills	154.6	139.6	15.0	11%	143.7	131.6	12.1	9%
SAOU	126.0	114.3	11.7	10%	121.1	110.0	11.1	10%
North Texas System	246.5	210.7	35.8	17%	237.9	197.4	40.5	21%
Versado	159.2	163.6	(4.4)	(3%)	166.3	165.4	0.9	1%
	686.3	628.2	58.1	9%	669.0	604.4	64.6	11%
Gross NGL production, MBbl/d								
Sand Hills	17.8	16.6	1.2	7%	16.8	15.5	1.3	8%
SAOU	19.5	17.8	1.7	10%	18.8	17.1	1.7	10%
North Texas System	26.6	22.9	3.7	16%	26.1	22.2	3.9	18%
Versado	19.0	17.8	1.2	7%	19.3	18.3	1.0	5%
	82.9	75.1	7.8	10%	81.0	73.1	7.9	11%
Natural gas sales, BBtu/d (3)	333.5	295.8	37.7	13%	319.9	281.2	38.7	14%
NGL sales, MBbl/d	68.7	60.2	8.5	14%	67.1	58.9	8.2	14%
Condensate sales, MBbl/d	3.4	3.0	0.4	13%	3.3	2.9	0.4	14%
Average realized prices (4):								
Natural gas, $/MMBtu	2.59	4.03	(1.44)	(36%)	2.40	3.96	(1.57)	(40%)
NGL, $/gal	0.79	1.29	(0.50)	(39%)	0.90	1.22	(0.31)	(26%)
Condensate, $/Bbl	86.82	85.99	0.83	1%	90.40	91.99	(1.59)	(2%)

(1) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

The decrease in gross margin was primarily due to lower natural gas and NGL sales prices, partially offset by higher throughput volumes. The increase in plant inlet volumes was largely attributable to new well connects, particularly at North Texas, Sand Hills and SAOU.

Operating expenses were relatively flat as additional compression related expenses due to system expansions and higher system maintenance and repair costs were offset by lower costs at Versado due to operational issues that impacted 2011.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The decrease in gross margin was primarily due to lower natural gas and NGL sales prices, partially offset by higher throughput volumes. The increase in plant inlet volumes was largely attributable to new well connects, particularly at North Texas, Sand Hills and SAOU, partially offset by pipeline curtailments and operational issues.

The increase in operating expenses was primarily due to additional compression related expenses due to system expansions and higher system maintenance and repair costs.

Coastal Gathering and Processing

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012	2011	2012 vs. 2011		2012	2011	2012 vs. 2011	
			($ in millions)					
Gross margin	$ 31.7	$ 52.9	$ (21.2)	(40%)	$ 127.2	$ 156.6	$ (29.4)	(19%)
Operating expenses (1)	13.7	13.1	0.6	5%	34.9	34.8	0.1	%
Operating margin	$ 18.0	$ 39.8	$ (21.8)	(55%)	$ 92.3	$ 121.8	$ (29.5)	(24%)
Operating statistics (2):								
Plant natural gas inlet, MMcf/d (3),(4)								
LOU (5)	324.5	170.7	153.8	90%	245.0	169.5	75.5	45%
Coastal Straddles	607.7	828.4	(220.7)	(27%)	735.5	897.8	(162.3)	(18%)
VESCO	350.0	459.7	(109.7)	(24%)	444.8	481.0	(36.2)	(8%)
	1,282.2	1,458.8	(176.6)	(12%)	1,425.3	1,548.3	(123.0)	(8%)
Gross NGL production, MBbl/d								
LOU	8.9	7.7	1.2	16%	8.4	7.1	1.3	18%
Coastal Straddles	14.8	16.4	(1.6)	(10%)	16.0	17.2	(1.2)	(7%)
VESCO	16.9	22.2	(5.3)	(24%)	21.1	24.8	(3.7)	(15%)
	40.6	46.3	(5.7)	(12%)	45.5	49.1	(3.6)	(7%)
Natural gas sales, BBtu/d (4)	317.2	256.6	60.6	24%	304.8	261.0	43.8	17%
NGL sales, MBbl/d	38.4	41.6	(3.2)	(8%)	42.1	43.0	(0.9)	(2%)
Condensate sales, MBbl/d	0.2	0.2	-	-	0.2	0.3	(0.1)	(33%)
Average realized prices (6):								
Natural gas, $/MMBtu	2.87	4.21	(1.33)	(32%)	2.59	4.24	(1.65)	(39%)
NGL, $/gal	0.85	1.35	(0.50)	(37%)	0.99	1.30	(0.30)	(23%)
Condensate, $/Bbl	96.07	107.72	(11.65)	(11%)	107.17	102.38	4.79	5%

(1) Costs associated with the clean-up and repair of Coastal Straddle plants resulting from the impact of Hurricane Isaac are reported as Other Operating Expenses and thus are not reflected in operating margin at the Coastal Gathering and Processing Segment level.
(2) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(3) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(4) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(5) Includes operations from the Big Lake processing plant acquired July 2012.
(6) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

The decrease in gross margin was primarily due to lower commodity sales prices, less favorable frac spread and lower throughput volumes. The decrease in plant inlet volumes was largely attributable to the decline in offshore and off-system supply volumes and the impact of Hurricane Isaac in August and September 2012 at the Coastal Straddle plants. The decrease was partially offset by an increase at LOU in supply volumes and the July 2012 acquisition of the Big Lake plant and gas purchased for processing at VESCO and Lowry. Natural gas sales volumes increased due to an increase in demand from industrial customers and increased sales to other reportable segments for resale.

The increase in operating expenses was primarily due to higher system maintenance and repair costs partially offset by lower utilities, power and catalysts costs.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The decrease in gross margin for year to date compared to 2011 was influenced by the factors described above for the three months. In addition, plant inlet volumes in the second quarter 2012 were impacted by planned operational outages at VESCO.

The impact of the Yscloskey plant is not material to the results of the Coastal Gathering and Processing Segment as it contributed approximately 2.7% of the Coastal Segment's gross NGL production for 2012, which accounted for less than 1% of operating margin for the nine months.

Operating expenses were flat as higher system maintenance and repair costs were offset by lower utilities, power and catalysts costs and higher refunds of operating expenses after ownership adjustments at non-operated joint ventures.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended September 30,		2012 vs. 2011		Nine Months Ended September 30,		2012 vs. 2011	
	2012	2011			2012	2011		
			($ in millions)					
Gross margin	$ 74.5	$ 57.5	$ 17.0	30%	$ 208.0	$ 157.0	$ 51.0	32%
Operating expenses	24.1	27.4	(3.3)	(12%)	68.8	71.1	(2.3)	(3%)
Operating margin	$ 50.4	$ 30.1	$ 20.3	67%	$ 139.2	$ 85.9	$ 53.3	62%
Operating statistics (1):								
Fractionation volumes, MBbl/d	293.3	290.4	2.9	1%	299.4	260.1	39.3	15%
Treating volumes, MBbl/d (2)	24.8	23.3	1.5	6%	23.7	20.5	3.2	16%

(1) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(2) Includes the volumes related to the natural gasoline hydrotreater at the Mt. Belvieu facility.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

Gross margin increased significantly due to higher treating, fractionation, terminaling and export activities. Gross margin improved due to higher treating volumes attributable to the benzene and depentanizer operations which started up in the first quarter 2012. Exporting and terminaling contributed to gross margin improvements as a result of substantially higher exports and the impact of the October 2011 Sound Terminal acquisition. Higher fractionation fees were partially offset by the impact of lower fuel prices which pass through to expenses.

Operating expenses decreased due to favorable system product gains and lower fuel costs (which have a corresponding impact on revenues), partially offset by an increase in operating costs associated with the October 2011 Sound Terminal acquisition.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The increase in gross margin was primarily due to higher fractionation and treating volumes, increased export and storage fees, and the impact of the 2011 petroleum logistics acquisitions. Higher fractionation volumes and fees were primarily attributable to the Cedar Bayou facility Train 3 expansion which came on line in mid-year 2011 (partially offset by the impact of lower fuel prices which pass through to expenses). Treating fees increased due to the operational startup of the benzene treating unit in the first quarter of 2012 and increased hydrotreating and depentanizer fees associated with increased volumes. Exporting and terminaling increased due to the same factors as described above.

The decrease in operating expenses was primarily due to favorable system product gains and lower fuel costs (which have a corresponding impact on revenues), partially offset by higher maintenance costs, increased operating costs due to greater hydrotreating and benzene unit run times, and the impact of a full nine months in 2012 of operating costs associated with petroleum logistics operations acquired in April and October of 2011.

Marketing and Distribution

	Three Months Ended September 30,		2012 vs. 2011		Nine Months Ended September 30,		2012 vs. 2011	
	2012	2011			2012	2011		
	($ in millions)							
Gross margin	$ 35.4	$ 30.1	$ 5.3	18%	$ 106.2	$ 116.0	$ (9.8)	(8%)
Operating expenses	10.0	10.4	(0.4)	(4%)	28.4	33.2	(4.8)	(14%)
Operating margin	$ 25.4	$ 19.7	$ 5.7	29%	$ 77.8	$ 82.8	$ (5.0)	(6%)
Operating statistics (1):								
Natural gas sales, BBtu/d	1,182.2	962.1	220.1	23%	1,100.9	829.1	271.8	33%
NGL sales, MBbl/d	289.4	264.5	24.9	9%	282.2	267.3	14.9	6%
Average realized prices:								
Natural gas, $/MMBtu	2.80	4.10	(1.30)	(32%)	2.54	4.15	(1.61)	(39%)
NGL realized price, $/gal	0.88	1.32	(0.44)	(33%)	1.00	1.32	(0.32)	(24%)

(1) Segment operating statistics include the effect of intersegment sales, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.

Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2011

The increase in gross margin was due to an increase in LPG export activity, favorable short-term wholesale propane marketing opportunities driven by regional supply conditions, and improved transportation opportunities. These favorable factors more than offset the effect of a weaker price environment. Export cargo volumes increased significantly and loading revenues increased compared to the same period last year.

Operating expenses were essentially flat due to increased truck operating costs offset by lower barge operating and maintenance costs.

Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2011

The decrease in gross margin was primarily due to a weaker price environment in 2012, partially offset by increased LPG export activity. Export cargo volumes increased significantly and export loading revenues increased compared to the same period last year. As in 2011, gross margin benefited from receipt of a contract settlement payment related to a multi-year contract propane exchange agreement ($3.8 million received year to date 2012 versus $7.5 million in 2011). The contract, as restructured, may result in the receipt of future payments in the fourth quarter and over the remaining term of the contract.

Operating expenses decreased due to significantly lower barge activity in 2012 compared to 2011, partially offset by increased truck operating costs.

Other

	Three Months Ended September 30,		2012 vs. 2011	Nine Months Ended September 30,		2012 vs. 2011
	2012	2011		2012	2011	
	(In millions)					
Gross margin	$ 14.0	$ (10.8)	$ 24.8	$ 28.1	$ (28.4)	$ 56.5
Operating margin	$ 14.0	$ (10.8)	$ 24.8	$ 28.1	$ (28.4)	$ 56.5

Other contains the financial effects of our hedging program on operating margin. It typically represents the cash settlements on our derivative contracts. Other also includes deferred gains or losses on previously terminated or de-designated hedge contracts that are reclassified to revenues upon the occurrence of the underlying physical transactions.

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent of proceeds processing arrangements by entering into derivative instruments. Because we are essentially forward selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices.

The following table provides a breakdown of our hedge revenue by product:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	2012 vs. 2011	2012	2011	2012 vs. 2011
			(In millions)			
Natural gas	$ 8.0	$ 6.4	$ 1.6	$ 26.9	$ 14.2	$ 12.7
NGL	6.0	(15.8)	21.8	3.5	(38.0)	41.5
Crude oil	-	(1.4)	1.4	(2.3)	(4.6)	2.3
	$ 14.0	$ (10.8)	$ 24.8	$ 28.1	$ (28.4)	$ 56.5

The increase in gross margin from our risk management activities was primarily due to lower natural gas and NGL prices.

Liquidity and Capital Resources

Our ability to finance our operations, including funding capital expenditures and acquisitions, meeting our indebtedness obligations, refinancing our indebtedness and meeting our collateral requirements, will depend 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. These include weather, commodity prices (particularly for natural gas and NGLs), ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

Our main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under our TRP Revolver, the issuance of additional common units and access to debt markets. The capital markets continue to experience volatility. Many financial institutions have had liquidity concerns, prompting government intervention to mitigate pressure on the credit markets. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. Continued volatility in the debt markets may increase costs associated with issuing debt instruments due to increased spreads over relevant interest rate benchmarks and affect our ability to access those markets. We continually monitor our liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders in our credit facility.

Subsequent Events

While interest rates and spreads can be volatile, absolute interest rates are low on a historical basis. In October 2012, we refinanced our Senior Secured Revolving Credit Facility, resulting in lowered funded borrowing costs, a reduction in commitment fees and an extended maturity.

Amended Credit Agreement

On October 3, 2012, we entered into a Second Amended and Restated Credit Agreement that amends and replaces our existing variable rate Senior Secured Credit Facility due July 2015 (the “Previous Revolver”) to provide a variable rate Senior Secured Credit Facility due October 3, 2017 (the “TRP Revolver”). The TRP Revolver increases available commitments to $1.2 billion from $1.1 billion and allows us to request up to an additional $300.0 million in commitment increases.

Senior Unsecured Notes

On October 19, 2012, we issued a call notice for full redemption of our 8¼% Notes, at a redemption price of 104.125% plus accrued interest through the redemption date of November 19, 2012. As of September 30, 2012, the outstanding balance on the 8¼% Notes was $209.1 million. The redemption will result in a premium paid on the redemption of $8.6 million and a write-off of $2.6 million of unamortized debt issue costs. The 8¼% Notes will be redeemed on November 19, 2012.

On October 25, 2012, we privately placed $400.0 million in aggregate principal amount 5¼% Notes at 99.5% of par value. The 5¼% Notes resulted in approximately $398.0 million of gross proceeds ($393.5 million of net proceeds), which will be used to redeem our 8¼% Notes, reduce borrowings under the TRP Revolver and for general partnership purposes.

As adjusted for the October 2012 Amended and Restated Credit Agreement, our liquidity as of September 30, 2012 consisted of the following:

	September 30, 2012
	(In millions)
Cash on hand	$ 88.9
Total availability under the Partnership's credit facility	1,200.0
Less: Outstanding borrowings under the Partnership's credit facility	(280.0)
Less: Outstanding letters of credit outstanding under the Partnership's credit facility	(47.4)
Total liquidity	$ 961.5

We may issue additional equity or debt securities to assist us in meeting future liquidity and capital spending requirements. We have filed with the SEC a universal shelf registration statement (the “2010 Shelf”), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. Our April 2010, August 2010, January 2011 and January 2012 equity offerings were conducted under the 2010 Shelf. The 2010 Shelf expires in April 2013.

We also have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $300 million of debt or equity securities (the “2012 Shelf”). In August 2012, we entered into an EDA with Citibank pursuant to which we may sell, at our option, up to an aggregate of $100 million of our common units through Citibank, as sales agent. Settlement for sales of common units will occur on the third business day following the date on which any sales were made in return for payment of the net proceeds to us. During the quarter ended September 30, 2012, there were no sales of common units pursuant to this program. The 2012 Shelf expires in August 2015.

Risk Management

We evaluate counterparty risks related to our commodity derivative contracts and trade credit. We have all of our commodity derivatives with major financial institutions or major oil companies. Should any of these financial counterparties not perform, we may not realize the benefit of some of our hedges under lower commodity prices, which could have a material adverse effect on our results of operation. We sell our natural gas, NGLs and condensate to a variety of purchasers. Non-performance by a trade creditor could result in losses.

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas equity volumes through 2015 and our NGL and condensate equity volumes through 2014 by entering into derivative instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for this period. See “Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk.” The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Our risk management position has moved from a net liability position of $5.0 million at December 31, 2011 to a net asset position of $31.6 million at September 30, 2012. Aggregate forward prices for commodities are below the fixed prices we currently expect to receive on those derivative contracts, creating a net asset position. Consequently, our expected future receipts on derivative contracts are greater than our expected future payments. We account for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with receivables from NGL customers offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (1) our cash position; (2) liquids inventory levels and their valuation, which we closely manage; and (3) changes in the fair value of the current portion of derivative contracts.

For the nine months ended September 30, 2012, our working capital increased by $79.8 million primarily due to higher cash balances ($33.3 million) and an increase in the net current portion of our derivative contracts ($27.6 million).

Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow, borrowings available under our Revolver and proceeds from equity offerings and debt offerings should provide sufficient resources to finance our operations, capital expenditures, long-term debt obligations, collateral requirements and minimum quarterly cash distributions for at least the next twelve months.

A significant portion of our capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While our credit ratings have improved over the last year, these letters of credit reflect our non-investment grade status, as assigned to us by Moody’s Investors Service, Inc. and Standard & Poor’s Corporation, and counterparties’ views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors.

Cash Flow

The following table and discussion summarize our consolidated cash flows provided by or used in operating activities, investing activities and financing activities:

	Nine Months Ended September 30,			
	2012	2011	2012 vs. 2011	
	(In millions)			
Net cash provided by (used in):				
Operating activities	$ 315.5	$ 191.3	$ 124.2	65%
Investing activities	(403.5)	(387.2)	(16.3)	4%
Financing activities	121.3	188.5	(67.2)	(36%)

Cash Flow from Operating Activities

Our Consolidated Statement of Cash Flows included in our historical consolidated financial statements employs the traditional indirect method of presenting cash flows from operating activities. Under the indirect method, net cash provided by operating activities is derived by adjusting our net income for non-cash items related to operating activities. An alternative GAAP presentation employs the direct method in which the actual cash receipts and outlays comprising cash flow are presented.

The following table displays our operating cash flows using the direct method as a supplement to the presentation in our financial statements:

	Nine Months Ended September 30,		
	2012	2011	2012 vs. 2011
Cash flows from operating activities:		(in millions)	
Cash received from customers	$ 4,502.0	$ 5,005.9	$ (503.9)
Cash received from (paid to) derivative counterparties	32.7	(47.7)	80.4
Cash outlays for:			
Product purchases	(3,808.2)	(4,379.5)	571.3
Operating expenses	(218.8)	(211.3)	(7.5)
General and administrative expenses	(110.5)	(97.3)	(13.2)
Cash distributions from equity investment	-	3.7	(3.7)
Interest paid, net of amounts capitalized (1)	(80.4)	(79.5)	(0.9)
Income taxes paid	(2.1)	(2.3)	0.2
Other cash payments	0.8	(0.7)	1.5
Net cash provided by operating activities	$ 315.5	$ 191.3	$ 124.2

(1) Net of capitalized interest paid of $8.5 million and $2.1 million included in investing activities for the nine months ended September 30, 2012 and 2011.

During the nine months ended September 30, 2012, lower aggregate commodity prices were the primary factor in the changes in cash from customers, cash from derivative contracts, cash paid for purchases and lower variable fuel components of our operating costs compared to the same period in 2011. During the nine months ended September 30, 2012, our derivative settlements were a net cash inflow, as opposed to a net outflow for the same period in 2011. The change in cash paid to derivative counterparties reflects lower aggregate commodity prices compared to the higher aggregate fixed prices we receive on those derivative contracts.

Cash Flow from Investing Activities

The increase in net cash used in investing activities was primarily due to an increase in outlays for property, plant and equipment driven by current capital expansion projects, offset by a reduction in amounts paid for business acquisitions and lower maintenance capital.

Cash Flow from Financing Activities

The decrease in net cash provided by financing activities was driven by distributions and changes in equity offerings and financing activities. Distributions to our unitholders increased for the nine months ended September 30, 2012 compared to the same period in 2011, while the sum of proceeds from public offerings, issuance of senior notes and net activity under our credit facility decreased.

Our primary financing activities that occurred during the nine months ended September 30, 2012 were:

- On January 23, 2012, we completed a public offering of 4,000,000 common units at a price of $38.30 per common unit. As part of this offering, a wholly-owned subsidiary of Targa purchased 1,300,000 common units. See Note 7, “Partnership Unit and Related Matters.”

- On January 31, 2012 we privately placed $400.0 million of 6⅜% Notes. See Note 6, “Debt Obligations.”

Distributions to our Unitholders

We distribute all available cash from our operating surplus. As a result, we expect that we will rely upon external financing sources, including debt and common unit issuances, to fund our acquisition and expansion capital expenditures. See Note 6 and Note 7 of the notes to Consolidated Financial Statements included in this Quarterly Report.

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). As of September 30, 2012, such annual minimum amounts would have been approximately $105.4 million. In every quarter since the fourth quarter of 2007, we have paid quarterly distributions greater than the minimum quarterly distribution rate. The quarterly distribution per limited partner unit to be paid in November 2012 for the third quarter of 2012 is $0.6425 per limited partner unit.

The following table details the distributions declared and/or paid during the first nine months of 2012:

		Distributions				
			General Partner			
Three Months Ended	Date Paid or to be Paid	Limited Partners Common	Incentive	2%	Total	Distributions per limited partner unit
		(In millions, except per unit amounts)				
September 30, 2012	November 14, 2012	$ 59.1	$ 16.1	$ 1.5	$ 76.7	$ 0.6625
June 30, 2012	August 14, 2012	57.3	14.4	1.5	73.2	0.6425
March 31, 2012	May 15, 2012	55.5	12.7	1.4	69.6	0.6225
December 31, 2011	February 14, 2012	53.7	11.0	1.3	66.0	0.6025

Capital Requirements

	Nine Months Ended September 30,	
	2012	2011
	(In millions)	
Gross additions to property, plant and equipment	$ 399.8	$ 242.1
Change in accruals	(9.2)	(1.7)
Cash expenditures	$ 390.6	$ 240.4

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

	Nine Months Ended September 30,	
	2012	2011
Capital expenditures:	(In millions)	
Business acquisitions	$ 25.8	$ 164.2
Expansion	326.0	155.9
Maintenance	48.0	57.2
	$ 399.8	$ 377.3

We estimate that our total capital expenditures for 2012 will be approximately $680 million gross. This amount includes approximately $600 million related to expansions and business acquisitions. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets.

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

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are set forth in Part II, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report. There have been no material changes to these policies and estimates during the nine months ended September 30, 2012.

Updates to our significant accounting policies can be found in Note 3 of our Consolidated Financial Statements in this Quarterly Report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For an in-depth discussion of market risks, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” in our Annual Report.

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, 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.

The primary purpose of the commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of September 30, 2012, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent of proceeds processing arrangements by entering into derivative instruments, including swaps and purchased puts (or floors) and calls (caps). The percentages of expected equity volumes that are hedged decrease over time. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGL and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into similar derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

We have tailored our hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. Our NGL hedges cover specific NGL products based upon our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Our natural gas and NGL hedges’ fair values are based on published index prices for delivery at various locations which closely approximate the actual natural gas and NGL delivery points. A portion of our condensate sales are hedged using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude.

These commodity price hedging transactions are typically documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. Our principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. Our payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges, are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Absent federal regulations resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act, and 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 expose our counterparties to credit risk, as we have no obligation to make future payments beyond the premium paid to enter into the transaction; however, we are exposed to the risk of default by the counterparty, which is the risk that the counterparty will not honor its obligation under the put transaction.

For all periods presented we have entered into hedging arrangements for a portion of our forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During the three months ended September 30, 2012 and 2011, our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $14.0 million and $(10.8) million. During the nine months ended September 30, 2012 and 2011, our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $28.1 million and $(28.4) million.

As of September 30, 2012, we had the following hedge arrangements which will settle during the years ending December 31, 2012 through 2015:

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu per day 2012	2013	2014	2015	Fair Value (in millions)
Swap	IF-WAHA	6.61	14,850	-	-	-	$ 4.7
Swap	IF-WAHA	4.68	-	10,730	-	-	3.6
Swap	IF-WAHA	3.53	-	-	7,000	-	(1.4)
Swap	IF-WAHA	3.53	-	-	-	1,750	(0.5)
Total Swaps			14,850	10,730	7,000	1,750	
Swap	IF-PB	4.98	10,200	-	-	-	1.7
Swap	IF-PB	4.69	-	10,084	-	-	3.6
Swap	IF-PB	3.49	-	-	6,000	-	(1.2)
Swap	IF-PB	3.49	-	-	-	1,500	(0.4)
Total Swaps			10,200	10,084	6,000	1,500	
Swap	IF-NGPL MC	6.03	6,740	-	-	-	1.8
Swap	IF-NGPL MC	4.17	-	5,275	-	-	0.9
Swap	IF-NGPL MC	3.45	-	-	5,000	-	(1.0)
Swap	IF-NGPL MC	3.46	-	-	-	1,250	(0.3)
Total Swaps			6,740	5,275	5,000	1,250	
Total Sales			31,790	26,089	18,000	4,500	
Natural Gas Basis Swaps							
Basis Swaps	Various Indexes, Maturities Through October 2013						0.3
							$ 11.8

NGL

Instrument Type	Index	Price $/Gal	Barrels per day 2012	2013	2014	Fair Value (in millions)
Swap	OPIS-MB	0.95	9,361	-	-	$ 5.2
Swap	OPIS-MB	1.05	-	5,650	-	11.0
Swap	OPIS-MB	1.21	-	-	1,000	3.9
Total Swaps			9,361	5,650	1,000	
Put (propane)	OPIS-MB	1.43	294	-	-	0.6
Total Sales			9,655	5,650	1,000	
Call (ethane) (1)	OPIS-MB	0.59	2,000			-
						$ 20.7

Condensate

Instrument Type	Index	Price $/Bbl	Barrels per day 2012	2013	2014	Fair Value (in millions)
Swap	NY-WTI	91.37	1,660	-	-	$ (0.2)
Swap	NY-WTI	93.34	-	1,795	-	(0.3)
Swap	NY-WTI	90.03	-	-	700	(0.4)
Total Sales			1,660	1,795	700	
						$ (0.9)

____

(1) Utilized in connection with 2,000 Bbl/d of 2012 ethane swaps providing a floor on ethane with upside.

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, 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 (other than with respect to purchased calls).

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant 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. 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 readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 9 to the Consolidated Financial Statements in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk. We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under our Revolver. Depending primarily on the level of our variable rate debt, we have historically and may in the future enter into interest rate hedges intended to mitigate the impact of changes in interest rates on our cash flows. To the extent that interest rates increase, interest expense for our Revolver will also increase. As of September 30, 2012, we had $280.0 million in variable rate borrowings under our Revolver. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense by $2.8 million.

Counterparty Credit Risk. We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

As of September 30, 2012, affiliates of Wells Fargo Bank N.A. (“Wells Fargo”), Barclays PLC (“Barclays”), Natixis and Credit Suisse Group AG (“Credit Suisse”) accounted for 24%, 20%, 15% and 11% of our counterparty credit exposure related to commodity derivative instruments. Wells Fargo, Barclays, Natixis and Credit Suisse are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody’s Investors Service, Inc. and Standard & Poor’s Corporation.

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

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and 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 Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2012, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this Quarterly Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended September 30, 2012 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 10 – Commitments and Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, 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. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Table of Contents

Item 6. Exhibits.

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	Amendment No. 2, dated May 25, 2012, to the 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 May 25, 2012 (File No. 001-33303)).
3.7	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 as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation and the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 25, 2012 (File No. 001-33303)).
4.2	Registration Rights Agreement dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 25, 2012 (File No. 001-33303)).
10.1	Second Amended and Restated Credit Agreement, dated October 3, 2012, 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 October 9, 2012 (File No. 001-33303)).
10.2	Purchase Agreement dated as of October 22, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 25, 2012 (File No. 001-33303)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document
*	Filed herewith
**	Furnished 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

Date: November 1, 2012 By: *<u>/s/ Matthew J. Meloy</u>*
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Authorized Officer and Principal Financial Officer)

Exhibit 31.1

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Joe Bob Perkins, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Targa Resources Partners LP (the “registrant”);

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

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

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

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

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

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

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

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

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

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

Date: November 1, 2012

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Matthew J. Meloy, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Targa Resources Partners LP (the “registrant”);

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

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

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

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

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

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

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

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

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

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

Date: November 1, 2012

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

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER 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 of Targa Resources Partners LP (the "Partnership") for the three months ended September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP

Date: November 1, 2012

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

Exhibit 32.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER 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 of Targa Resources Partners LP (the “Partnership”) for the three months ended September 30, 2012 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Matthew J. Meloy , as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP

Date: November 1, 2012

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.