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

FORM 10-Q

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

For the quarterly period ended June 30, 2013

or

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

For the transition period from _____ to _____

Commission File Number: 001-33303

TARGA RESOURCES PARTNERS LP

(Exact name of registrant as specified in its charter)

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

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 ☑ No o.

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

Large accelerated filer ☑	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o
		(Do not check if a 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 o No ☑.

As of July 26, 2013, there were 106,080,164 common units and 2,164,903 general partner units outstanding.

PART I—FINANCIAL INFORMATION

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we," "us," "our," or "the Partnership") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking by the use of forward-looking statements, 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"), crude oil 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 crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering 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, 2012 ("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.

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

Bbl	Barrels (equal to 42 U.S. 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

	June 30, 2013	December 31, 2012
	(Unaudited) (In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72.7	$ 68.0
Trade receivables, net of allowances of $0.9 million and $0.7 million	435.9	514.9
Inventories	138.3	99.4
Assets from risk management activities	23.2	29.3
Other current assets	1.8	3.3
Total current assets	671.9	714.9
Property, plant and equipment	5,159.9	4,701.2
Accumulated depreciation	(1,281.3)	(1,168.0)
Property, plant and equipment, net	3,878.6	3,533.2
Other intangible assets, net	667.1	680.8
Long-term assets from risk management activities	5.6	5.1
Investment in unconsolidated affiliate	57.6	53.1
Other long-term assets	41.8	38.6
Total assets	$ 5,322.6	$ 5,025.7
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 567.1	$ 639.8
Accounts payable to Targa Resources Corp.	49.8	61.4
Liabilities from risk management activities	3.8	7.4
Total current liabilities	620.7	708.6
Long-term debt	2,650.0	2,393.3
Long-term liabilities from risk management activities	1.8	4.8
Deferred income taxes	12.0	11.2
Other long-term liabilities	51.4	47.7
Commitments and contingencies (see Note 12)		
Owners' equity:		
Common unitholders (106,080,164 and 100,095,989 units issued and outstanding as of June 30, 2013 and December 31, 2012)	1,788.8	1,649.5
General partner (2,164,903 and 2,042,776 units issued and outstanding as of June 30, 2013 and December 31, 2012)	52.8	45.3
Receivables from unit offerings	(34.2)	-
Accumulated other comprehensive income	19.1	14.8
	1,826.5	1,709.6
Noncontrolling interests in subsidiaries	160.2	150.5
Total owners' equity	1,986.7	1,860.1
Total liabilities and owners' equity	$ 5,322.6	$ 5,025.7

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(Unaudited) (In millions, except per unit amounts)			
Revenues	$ 1,441.6	$ 1,318.4	$ 2,839.5	$ 2,963.9
Costs and expenses:				
Product purchases	1,176.4	1,074.6	2,313.9	2,458.7
Operating expenses	96.1	77.2	182.1	148.8
Depreciation and amortization expenses	65.7	47.6	129.6	94.3
General and administrative expenses	36.1	33.5	70.3	66.4
Other operating (income) expense	4.1	-	4.2	(0.1)
Income from operations	63.2	85.5	139.4	195.8
Other income (expense):				
Interest expense, net	(31.6)	(29.4)	(63.0)	(58.8)
Equity earnings (loss)	2.9	(0.2)	4.5	1.9
Loss on debt redemption	(7.4)	-	(7.4)	-
Other	6.5	(0.4)	6.3	(0.5)
Income before income taxes	33.6	55.5	79.8	138.4
Income tax expense:				
Current	(0.5)	(0.4)	(1.0)	(1.0)
Deferred	(0.4)	(0.4)	(0.8)	(0.8)
	(0.9)	(0.8)	(1.8)	(1.8)
Net income	32.7	54.7	78.0	136.6
Less: Net income attributable to noncontrolling interests	6.4	7.9	12.8	19.6
Net income attributable to Targa Resources Partners LP	$ 26.3	$ 46.8	$ 65.2	$ 117.0
Net income attributable to general partner	25.1	15.4	$ 47.9	$ 29.5
Net income attributable to limited partners	1.2	31.4	17.3	87.5
Net income attributable to Targa Resources Partners LP	$ 26.3	$ 46.8	$ 65.2	$ 117.0
Net income per limited partner unit - basic	$ 0.01	$ 0.35	$ 0.17	$ 0.99
Net income per limited partner unit - diluted	$ 0.01	$ 0.35	$ 0.17	$ 0.99
Weighted average limited partner units outstanding - basic	103.9	89.2	102.9	88.6
Weighted average limited partner units outstanding - diluted	104.2	89.3	103.1	88.7

See notes to consolidated financial statements.

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

	Three Months Ended June 30,					
	2013			2012		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
			(Unaudited) (In millions)			
Net income			$ 32.7			$ 54.7
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ 21.1	$ -	21.1	$ 77.3	$ (0.5)	76.8
Settlements reclassified to revenues	(5.9)	-	(5.9)	(12.9)	0.1	(12.8)
Interest rate swaps:						
Settlements reclassified to interest expense, net	1.6	-	1.6	1.9	-	1.9
Other comprehensive income (loss)	$ 16.8	$ -	16.8	$ 66.3	$ (0.4)	65.9
Comprehensive income			49.5			120.6
Less: Comprehensive income attributable to noncontrolling interests			6.4			7.9
Comprehensive income attributable to Targa Resources Partners LP			$ 43.1			$ 112.7

	Six Months Ended June 30,					
	2013			2012		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
			(Unaudited) (In millions)			
Net income			$ 78.0			$ 136.6
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ 13.6	$ -	13.6	$ 92.8	$ (0.5)	92.3
Settlements reclassified to revenues	(12.6)	-	(12.6)	(15.1)	0.1	(15.0)
Interest rate swaps:						
Settlements reclassified to interest expense, net	3.3	-	3.3	4.2	-	4.2
Other comprehensive income	$ 4.3	$ -	4.3	$ 81.9	$ (0.4)	81.5
Comprehensive income			82.3			218.1
Less: Comprehensive income attributable to noncontrolling interests			12.8			19.6
Comprehensive income attributable to Targa Resources Partners LP			$ 69.5			$ 198.5

See notes to consolidated financial statements.

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

	Limited Partner		General Partner		Receivables From Unit	Accumulated Other Comprehensive	Non-controlling	
	Units	Amount	Units	Amount	Offerings	Income (Loss)	Interests	Total
	(Unaudited) (In millions, except units in thousands)							
Balance December 31, 2012	100,096	$ 1,649.5	2,043	$ 45.3	$ -	$ 14.8	$ 150.5	$ 1,860.1
Compensation on equity grants	13	3.0	-	-	-	-	-	3.0
Accrual of distribution equivalent rights	-	(0.7)	-	-	-	-	-	(0.7)
Equity offerings	5,971	260.3	122	5.4	(34.2)	-	-	231.5
Distributions to noncontrolling interests	-	-	-	-	-	-	(7.4)	(7.4)
Contributions from noncontrolling interests	-	-	-	-	-	-	4.3	4.3
Other comprehensive loss	-	-	-	-	-	4.3	-	4.3
Net income	-	17.3	-	47.9	-	-	12.8	78.0
Distributions	-	(140.6)	-	(45.8)	-	-	-	(186.4)
Balance June 30, 2013	106,080	$ 1,788.8	2,165	$ 52.8	$ (34.2)	$ 19.1	$ 160.2	$ 1,986.7
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	1.6	-	-	-	-	-	1.6
Proceeds from equity offerings, net	4,405	164.9	90	3.5	-	-	-	168.4
Contributions from Targa Resources Corp.	-	0.7	-	0.1	-	-	-	0.8
Distributions to noncontrolling interests	-	(1.2)	-	-	-	-	(15.0)	(16.2)
Contributions from noncontrolling interests	-	-	-	-	-	-	4.8	4.8
Other comprehensive income	-	-	-	-	-	81.5	-	81.5
Net income	-	87.5	-	29.5	-	-	19.6	136.6
Distributions to unitholders	-	(109.2)	-	(26.4)	-	-	-	(135.6)
Balance June 30, 2012	89,171	$ 1,365.5	1,820	$ 33.9	$ -	$ 55.9	$ 148.3	$ 1,603.6

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income	$ 78.0	$ 136.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	8.0	9.1
Compensation on equity grants	3.0	1.6
Depreciation and amortization expense	129.6	94.3
Accretion of asset retirement obligations	2.0	2.0
Deferred income tax expense	0.8	0.8
Equity earnings, net of distributions	(4.5)	-
Risk management activities	(0.1)	2.0
Loss (gain) on sale or disposition of assets	3.8	(0.1)
Loss on debt redemption	7.4	-
Changes in operating assets and liabilities:		
Receivables and other assets	81.0	209.0
Inventory	(49.5)	(0.3)
Accounts payable and other liabilities	(82.7)	(230.0)
Net cash provided by operating activities	176.8	225.0
Cash flows from investing activities		
Outlays for property, plant and equipment	(444.5)	(238.4)
Investment in unconsolidated affiliate	-	(13.7)
Other, net	(10.5)	1.3
Net cash used in investing activities	(455.0)	(250.8)
Cash flows from financing activities		
Proceeds from borrowings under credit facility	680.0	325.0
Repayments of credit facility	(1,075.0)	(683.0)
Proceeds from issuance of senior notes	625.0	400.0
Proceeds from accounts receivable securitization facility	207.7	-
Repayments of accounts receivable securitization facility	(82.4)	-
Redemption of senior notes	(106.4)	-
Costs incurred in connection with financing arrangements	(11.7)	(4.5)
Proceeds from equity offerings	235.2	168.4
Distributions to unitholders	(186.4)	(135.6)
General partner contributions	-	0.8
Contributions from noncontrolling interests	4.3	4.8
Distributions to noncontrolling interests	(7.4)	(16.2)
Net cash provided by (used in) financing activities	282.9	59.7
Net change in cash and cash equivalents	4.7	33.9
Cash and cash equivalents, beginning of period	68.0	55.6
Cash and cash equivalents, end of period	$ 72.7	$ 89.5

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.

Note 1 — Organization and Operations

Our Organization

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.

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 June 30, 2013, Targa owned a 14.0% interest in us in the form of 2,164,903 general partner units and 12,945,659 common units. In addition, Targa Resources GP LLC also 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.

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling natural gas liquids ("NGL") and NGL products; gathering, storing and terminaling crude oil; and storing, terminaling and selling refined petroleum products. See Note 14 for certain financial information for our business segments.

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 six months ended June 30, 2013 and 2012 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 may have been reclassified to conform to the current year presentation.

Our financial results for the three and six months ended June 30, 2013 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2013.

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 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, 2012. Significant updates or revisions to these policies during the six months ended June 30, 2013 are shown below.

Accounts Receivable Securitization Facility

Proceeds from the sales of certain receivables under our Accounts Receivable Securitization Facility (the "Securitization Facility") are treated as collateralized borrowings in our financial statements. Such borrowings are reflected as long-term debt on our balance sheets to the extent that we have the ability and intent to fund the Securitization Facility's borrowings on a long-term basis. Proceeds and repayments under the Securitization Facility are reflected as cash flows from financing activities on our statements of cash flows.

Intangible Assets

Intangible assets arose from producer dedications under long-term contracts and customer relationships associated with businesses acquisitions. The fair value of these acquired intangible assets was determined at the date of acquisition based on the present value of estimated future cash flows. Amortization expense attributable to these assets is recorded in a manner that closely resembles the expected pattern in which we benefit from services provided to customers.

Recent Accounting Pronouncements

In January 2013, the FASB issued Accounting Standards Update No. 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*, which clarifies that ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*, applies to financial instruments or derivative transactions accounted for under ASC 815. The amendments require disclosures to present both gross and net amounts of derivative assets and liabilities that are subject to master netting arrangements with counterparties. We currently present our derivative assets and liabilities on a gross basis on our statement of financial position. We have provided additional disclosures regarding the gross and net amounts of derivative assets and liabilities in Note 10 in accordance with these new standards updates.

Note 4 –Business Acquisitions

On December 31, 2012, we completed the acquisition of Saddle Butte Pipeline, LLC's ownership of its Williston Basin crude oil pipeline and terminal system and its natural gas gathering and processing operations (collectively "Badlands").

Pursuant to the Membership Interest Purchase and Sale Agreement dated November 19, 2012 (the "MIPSA"), the acquisition is subject to a contingent payment of $50 million ("the contingent consideration") if aggregate crude oil gathering volumes exceed certain stipulated monthly thresholds during the period from January 2013 through June 2014. If the threshold is not attained during the contingency period, no payment is owed. Accounting standards require that the contingent consideration be recorded at fair value at the date of acquisition and revalued at subsequent reporting dates under the acquisition method of accounting and revalued during the contingency period. At December 31, 2012, we recorded a $15.3 million accrued liability representing the fair value of this contingent consideration, determined by a probability based model measuring the likelihood of meeting certain volumetric measures identified in the MIPSA.

Changes in the fair value of this accrued liability are included in earnings and reported as Other income (expense) in the Consolidated Statement of Operations. At June 30, 2013, we re-estimated the contingent consideration to be $9.1 million, a decrease of $6.2 million from the December 31, 2012 valuation. The change in the contingent liability reflects management's updated assessment, with only one-year remaining on the contingency period, of the likelihood of meeting the stipulated volumetric thresholds, net of accretion of the discount factor due to the passage of time.

Our Annual Report on Form 10-K included the pro-forma schedule information for the year ended 2012. The following table presents updated 2012 pro forma information to reflect the effects of our 2013 policy decisions regarding depreciation and amortization of acquired properties and intangible assets, as described below. The following table also presents quarterly unaudited pro forma information for the three and six months ended June 30, 2012 for comparative purposes in this quarterly report.

	Year Ended December 31, 2012		Three Months Ended June 30, 2012	Six Months Ended June 30, 2012
	As reported in 10-K	Pro forma	Pro forma	Pro forma
	(In millions except per unit amounts)			
Revenues	$ 5,883.6	$ 5,907.8	$ 1,323.3	$ 2,971.7
Net income	203.2	157.4	40.9	107.4
Net income attributable to limited partners	107.9	63.1	17.9	58.9
Net income per limited partner unit - Basic and diluted	$ 1.20	$ 0.63	$ 0.18	$ 0.59

We applied the same assumptions used in preparing the year-end pro forma schedules reported in our Annual Report on Form 10-K except for the following adjustments to conform to our current accounting policies:

- depreciation expense associated with the fair value adjustments to property, plant and equipment using the straight-line method over a useful life of 15-20 years. The pro forma information included in our 2012 Form 10-K utilized a 30 year useful life;

- amortization expense associated with the fair value adjustments to definite-lived intangibles in a manner that follows the expected pattern of services provided to customers, over a useful life of 20 years. The pro forma information included in our 2012 Form 10-K utilized a straight-line method over a 30 year life; and

- adjustment to pro forma revenues to report purchases, and sales on a net, rather than gross, basis for certain Badlands natural gas processing agreements in which we are in substance an agent rather than a principal.

Note 5 — Inventories

The components of inventories consisted of the following:

	June 30, 2013	December 31, 2012
Natural gas liquids	$ 109.5	$ 82.3
Materials and supplies	28.8	17.1
	$ 138.3	$ 99.4

Note 6 — Property, Plant and Equipment and Intangible Assets

	June 30, 2013	December 31, 2012	Estimated useful lives (In years)
Gathering systems	$ 2,075.7	$ 1,975.3	5 to 20
Processing and fractionation facilities	1,269.4	1,251.6	5 to 25
Terminaling and storage facilities	526.0	462.0	5 to 25
Transportation assets	292.6	292.5	10 to 25
Other property, plant and equipment	88.7	84.6	3 to 25
Land	87.4	87.1	-
Construction in progress	820.1	548.1	-
Property, plant and equipment	$ 5,159.9	$ 4,701.2	
Accumulated depreciation	(1,281.3)	(1,168.0)	
Property, plant and equipment, net	$ 3,878.6	$ 3,533.2	
Intangible assets	$ 681.8	$ 681.9	20
Accumulated amortization	(14.7)	(1.1)	
Intangible assets, net	$ 667.1	$ 680.8	

Intangible assets consist of customer contracts and customer relationships acquired in business acquisitions. The fair value of these acquired intangible assets was determined at the date of acquisition based on the present value of estimated future cash flows. Key valuation assumptions include probability of contracts under negotiation, renewals of existing contracts, economic incentives to retain customers, past and future volumes, current and future capacity of the gathering system, pricing volatility and the discount rate.

Customer contracts and customer relationships related to the Badlands system have an estimated economic useful life of 20 years. Amortization expense attributable to these assets is recorded using a method that closely reflects the cash flow pattern underlying the intangible asset valuation. The estimated amortization expense for these intangible assets is approximately $27.1 million, $61.4 million, $80.1 million, $88.3 million and $81.5 million for each of years 2013 through 2017.

Note 7 — Accounts Payable and Accrued Liabilities

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

	June 30, 2013	December 31, 2012
Commodities	$ 365.9	$ 416.8
Other goods and services	141.2	153.4
Interest	39.7	39.4
Other	20.3	30.2
	$ 567.1	$ 639.8

Note 8 — Debt Obligations

	June 30, 2013	December 31, 2012
Senior secured revolving credit facility, variable rate, due October 2017 (1)	$ 225.0	$ 620.0
Senior unsecured notes, 11¼% fixed rate, due July 2017 (2)	72.7	72.7
Unamortized discount	(2.3)	(2.5)
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	(29.3)	(30.5)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	300.0	400.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0	-
Accounts receivable securitization facility, due January 2014 (3)	125.3	-
Total long-term debt	$ 2,650.0	$ 2,393.3
Letters of credit outstanding	$ 47.9	$ 45.3

(1) As of June 30, 2013, availability under our $1.2 billion senior secured revolving credit facility was $927.1 million.
(2) The outstanding balance of the 11¼% Notes was redeemed on July 15, 2013. The amounts outstanding are reflected as long-term debt as of June 30, 2013 in our balance sheet because we have the ability and intent to fund these borrowings with availability under our long-term Senior Secured Credit Facility (the "TRP Revolver"). See "Subsequent Events" below.
(3) All amounts outstanding under the Securitization Facility are reflected as long-term debt in our balance sheet because we have the ability and intent to fund the Securitization Facility's borrowing with availability under the TRP Revolver.

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the six months ended June 30, 2013:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	1.9% - 4.5%	2.3%
Accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

As of June 30, 2013, we were in compliance with the covenants contained in our various debt agreements.

Accounts Receivable Securitization Facility

In January 2013, we entered into the Securitization Facility to provide up to $200 million of borrowing capacity at commercial paper rates plus a margin through January 2014. Under this Securitization Facility, one of our consolidated subsidiaries (Targa Liquids Marketing and Trade LLC or "TLMT") sells or contributes receivables, without recourse, to another of our consolidated subsidiaries (Targa Receivables LLC or "TRLLC"), a special purpose consolidated subsidiary created for the sole purpose of this Securitization Facility. TRLLC, in turn, sells an undivided percentage ownership in the eligible receivables to a third-party financial institution. Eligible TRLLC receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of TLMT or us. Any excess receivables are eligible to satisfy the claims of creditors of TLMT or us.

April 2013 Shelf

In April 2013, we filed with the SEC a universal shelf registration statement (the "April 2013 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. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the six months ended June 30, 2013.

4¼% Senior Notes due 2023 ("4¼% Notes")

In May 2013, we privately placed $625.0 million in aggregate principal amount of 4¼% Senior Notes. The 4¼% Notes resulted in approximately $618.1 million of net proceeds, which were used to reduce borrowings under our senior secured revolving credit facility and for general partnership purposes.

The 4¼% Notes are unsecured senior obligations that rank pari passu in right of payment with existing and future senior indebtedness. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by certain of our subsidiaries. The 4¼% 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 4¼% Notes accrues at the rate of 4¼% per annum and is payable semi-annually in arrears on May 15 and November 15, commencing on November 15, 2013.

We may redeem 35% of the aggregate principal amount of the 4¼% Notes at any time prior to May 15, 2016, with the net cash proceeds of one or more equity offerings. We must pay a redemption price of 104.25% of the principal amount, plus accrued and unpaid interest and liquidated damages, if any, to the redemption date provided that:

1) at least 65% of the aggregate principal amount of the 4¼% Notes (excluding the 4¼% 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 4¼% Notes on or after May 15, 2018 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 May 15 of each year indicated below.

Year	Redemption Price
2018	102.125%
2019	101.417%
2020	100.708%
2021 and thereafter	100.000%

Senior Notes Repayments and Redemptions

In June 2013, we paid $106.4 million plus accrued interest to redeem $100 million of the outstanding 6⅜% Senior Notes due 2022 (the "6⅜% Notes"). The redemption resulted in a $7.4 million loss on debt redemption, consisting of a premium paid of $6.4 million, and a write-off of $1.0 million of unamortized debt issue costs.

Subsequent Events

On July 15, 2013, we paid $76.8 million plus accrued interest per the terms of the note agreement to redeem the outstanding balance of the 11¼% Senior Notes due 2017 (the "11¼% Notes"). The redemption resulted in a $7.4 million loss on debt redemption in the third quarter 2013, consisting of a premium paid of $4.1 million, and non-cash losses to write-off $2.3 million of unamortized notes discounts and $1.0 million of unamortized debt issue costs.

On July 29, 2013, 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 $800 million of debt or equity securities (the "July 2013 Shelf"). The July 2013 Shelf expires in August 2016.

Note 9 — Partnership Units and Related Matters

Public Offerings of Common Units

In 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"). The 2012 Shelf expires in August 2015.

In August 2012, we entered into an Equity Distribution Agreement ("2012 EDA") with Citigroup Global Markets Inc. ("Citigroup") 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, under the 2012 Shelf. Settlement for sales of common units occurs on the third business day following the date on which any sales were made. During the six months ended June 30, 2013, we issued 2,420,046 common units under the 2012 EDA, receiving net proceeds of $94.8 million. Targa contributed $2.0 million to us to maintain its 2% general partner interest.

In March 2013, we entered into a second Equity Distribution Agreement under our 2012 Shelf ("2013 EDA") with Citigroup, Deutsche Bank Securities Inc., Raymond James & Associates, Inc. and UBS Securities LLC, as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $200 million of our common units During the six months ended June 30, 2013, we issued 3,551,349 common units receiving net proceeds of $165.5 million, of which $32.8 million was received in July 2013 and reported as a receivable in Owners' Equity. During the six months ended June 30, 2013, Targa contributed $5.4 million to maintain its 2% general partner interest of which $1.4 million was settled in July and reported as a receivable in Owners' Equity.

Distributions

In accordance with the partnership agreement, we must distribute all of our available cash, as determined by the general partner, to unitholders of record within 45 days after the end of each quarter. The following table details the distributions declared and/or paid by us during the six months ended June 30, 2013.

		Distributions				
		Limited Partners	General Partner			Distributions per limited partner unit
Three Months Ended	Date Paid or to be Paid	Common	Incentive	2%	Total	
		(In millions, except per unit amounts)				
June 30, 2013	August 14, 2013	$ 75.8	$ 24.6	$ 2.0	$ 102.4	$ 0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	0.6975
December 31, 2012	February 14, 2013	69.0	20.1	1.8	90.9	0.6800

Note 10 — Derivative Instruments and Hedging Activities

Commodity Hedges

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 prices 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 segment and the LOU business unit in Coastal Gathering and Processing segment that result from its percent of proceeds processing arrangements. These hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices. We have designated these derivative contracts as cash flow hedges for accounting purposes.

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 condensate equity volumes.

At June 30, 2013, the notional volumes of our commodity hedges for equity volumes were:

Commodity	Instrument	Unit	2013	2014	2015	2016
Natural Gas	Swaps	MMBtu/d	41,090	33,050	19,551	10,000
NGL	Swaps	Bbl/d	5,650	1,000	-	-
Condensate	Swaps	Bbl/d	2,045	1,450	-	-

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.

Our derivative contracts are subject to netting arrangements that allow net cash settlement of offsetting asset and liability positions with the same counterparty. We record derivative assets and liabilities on our Consolidated Balance Sheets on a gross basis, without considering the effect of master netting arrangements. The following schedules reflect the fair values of our derivative instruments and their location in our Consolidated Balance Sheets as well as pro forma reporting assuming that we reported derivatives subject to master netting agreements on a net basis:

		Fair Value as of June 30, 2013		Fair Value as of December 31, 2012	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 23.2	$ 3.5	$ 29.2	$ 7.2
	Long-term	5.6	1.8	5.1	4.8
Total derivatives designated as hedging instruments		$ 28.8	$ 5.3	$ 34.3	$ 12.0
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ -	$ 0.3	$ 0.1	$ 0.2
Total derivatives not designated as hedging instruments		$ -	$ 0.3	$ 0.1	$ 0.2
Total current position		$ 23.2	$ 3.8	$ 29.3	$ 7.4
Total long-term position		5.6	1.8	5.1	4.8
Total derivatives		$ 28.8	$ 5.6	$ 34.4	$ 12.2

The pro forma impact of reporting derivatives in the Consolidated Balance Sheet is as follows:

	Gross Presentation		Pro forma Net Presentation	
June 30, 2013	**Asset Position**	**Liability Position**	**Asset Position**	**Liability Position**
Current position				
Counterparties with offsetting position	$ 20.6	$ 3.2	$ 17.4	$ -
Counterparties without offsetting position - assets	2.6	-	2.6	-
Counterparties without offsetting position - liabilities	-	0.6	-	0.6
	23.2	3.8	20.0	0.6
Long-term position				
Counterparties with offsetting position	4.1	0.8	3.3	-
Counterparties without offsetting position - assets	1.5	-	1.5	-
Counterparties without offsetting position - liabilities	-	1.0	-	1.0
	5.6	1.8	4.8	1.0
Total derivatives				
Counterparties with offsetting position	24.7	4.0	20.7	-
Counterparties without offsetting position - assets	4.1	-	4.1	-
Counterparties without offsetting position - liabilities	-	1.6	-	1.6
	$ 28.8	$ 5.6	$ 24.8	$ 1.6
December 31, 2012				
Current position				
Counterparties with offsetting position	$ 23.8	$ 7.4	$ 16.4	$ -
Counterparties without offsetting position - assets	5.5	-	5.5	-
Counterparties without offsetting position - liabilities	-	-	-	-
	29.3	7.4	21.9	-
Long-term position				
Counterparties with offsetting position	4.4	2.8	1.6	-
Counterparties without offsetting position - assets	0.7	-	0.7	-
Counterparties without offsetting position - liabilities	-	2.0	-	2.0
	5.1	4.8	2.3	2.0
Total derivatives				
Counterparties with offsetting position	28.2	10.2	18.0	-
Counterparties without offsetting position - assets	6.2	-	6.2	-
Counterparties without offsetting position - liabilities	-	2.0	-	2.0
	$ 34.4	$ 12.2	$ 24.2	$ 2.0

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 $23.2 million as of June 30, 2013. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented.

Our payment obligations in connection with substantially all of these hedging transactions 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 June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Commodity contracts	$ 21.1	$ 77.3	$ 13.6	$ 92.8
	$ 21.1	$ 77.3	$ 13.6	$ 92.8

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Interest expense, net	$ (1.6)	$ (1.9)	$ (3.3)	$ (4.2)
Revenues	5.9	12.9	12.6	15.1
	$ 4.3	$ 11.0	$ 9.3	$ 10.9

Hedge ineffectiveness was immaterial for all periods presented.

Our consolidated earnings are also affected by our 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. Gain (loss) recognized on derivatives not designated as hedging instruments was immaterial for all periods presented.

The following table shows the deferred gains (losses) included in accumulated OCI that will be reclassified into earnings through the end of 2016:

	June 30, 2013	December 31, 2012
Commodity hedges	$ 24.2	$ 23.1
Interest rate hedges	(5.1)	(8.5)

As of June 30, 2013, net gains of $20.4 million on commodity hedges and net losses of $5.1 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 11 for additional disclosures related to derivative instruments and hedging activities.

Note 11 — 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.

The 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 $23.2 million as of June 30, 2013, 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 liability of $0.8 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 $47.3 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

The contingent consideration obligation related to our Badlands acquisition is reported at fair value. 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:

- TRP Revolver and Securitization Facility are 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:

	June 30, 2013				
		Fair Value			
	Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$ 28.5	$ 28.5	$ -	$ 28.0	$ 0.5
Liabilities from commodity derivative contracts	5.3	5.3	-	4.8	0.5
Badlands contingent consideration liability	9.1	9.1	-	-	9.1
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	72.7	72.7	-	-	-
Senior secured revolving credit facility	225.0	225.0	-	225.0	-
Senior unsecured notes	2,299.7	2,317.5	-	2,317.5	-
Accounts receivable securitization facility	125.3	125.3	-	125.3	-

	December 31, 2012				
	Carrying	Fair Value			
	Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$ 34.3	$ 34.3	$ -	$ 34.3	$ -
Liabilities from commodity derivative contracts	12.1	12.1	-	11.5	0.6
Badlands contingent consideration liability	15.3	15.3	-	-	15.3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	68.0	68.0	-	-	-
Senior secured revolving credit facility	620.0	620.0	-	620.0	-
Senior unsecured notes	1,773.3	1,945.2	-	1,945.2	-

Additional Information Regarding Level 3 Fair Value Measurements Included in Our Consolidated Balance Sheet

As of June 30, 2013, 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 June 30, 2013, we had several 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 curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

In 2012, we recorded a contingent consideration liability as part of the purchase consideration for the Badlands acquisition (see Note 4). The fair value of this contingent liability was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures identified in the MIPSA. At June 30, 2013, with only one year remaining in the contingent consideration period, management re-estimated the contingent liability, reflecting its updated assessments of the likelihood of meeting the stipulated volumetric thresholds, net of accretion of the discount factor due to the passage of time. Consequently, as these probability-based inputs are not observable, the entire valuation of the contingent consideration is categorized in Level 3.

The following table summarizes the changes in fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts	Contingent Liability
Balance, December 31, 2012	$ (0.6)	$ (15.3)
Settlements included in Revenue	0.6	-
Change in valuation of contingent liability included in Other Income	-	6.2
Balance, June 30, 2013	$ -	$ (9.1)

There have been no transfers of assets or liabilities between the three levels of the fair value hierarchy during the six months ended June 30, 2013.

Note 12 — Commitments and Contingencies

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 13 - Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2013	2012
Cash:		
Interest paid, net of capitalized interest	$ 54.6	$ 39.4
Income taxes paid, net of refunds	2.3	2.0
Non-cash:		
Deadstock inventory transferred to property, plant and equipment	22.2	2.8
Accrued distribution equivalent rights	0.7	-
Receivables from unit offerings	34.2	-

Note 14 — Segment Information

We report our operations in two divisions: (i) 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 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. With the Badlands acquisition on December 31, 2012, this segment's assets now include the Badlands crude oil and natural gas gathering, terminaling and processing assets in North Dakota. Because the acquisition closed on December 31, 2012, Badlands had no operational impact for 2012. 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, 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, as well as transporting natural gas and NGLs.

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs, including services for exported LPGs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana.

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; providing propane, butane and services to LPG exporters; and (4) marketing natural gas available to us from our 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 June 30, 2013						
	Field Gathering and Processing	**Coastal Gathering and Processing**	**Logistics Assets**	**Marketing and Distribution**	**Other**	**Corporate and Eliminations**	**Total**
Revenues							
Sales of commodities	$ 51.1	$ 83.1	$ 45.4	$ 1,142.4	$ 5.6	$ (0.1)	$ 1,327.5
Fees from midstream services	22.6	9.8	47.4	34.2	-	0.1	114.1
	73.7	92.9	92.8	1,176.6	5.6	-	1,441.6
Intersegment revenues							
Sales of commodities	291.0	135.8	0.9	125.7	-	(553.4)	-
Fees from midstream services	0.7	-	33.3	6.1	-	(40.1)	-
	291.7	135.8	34.2	131.8	-	(593.5)	-
Revenues	$ 365.4	$ 228.7	$ 127.0	$ 1,308.4	$ 5.6	$ (593.5)	$ 1,441.6
Operating margin	$ 67.3	$ 16.7	$ 52.1	$ 27.4	$ 5.6	$ -	$ 169.1
Other financial information:							
Total assets	$ 2,950.9	$ 403.9	$ 1,303.6	$ 509.6	$ 28.8	$ 125.8	$ 5,322.6
Capital expenditures	$ 115.1	$ 4.3	$ 114.1	$ 0.8	$ -	$ 1.4	$ 235.7

	Three Months Ended June 30, 2012						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 46.6	$ 51.7	$ 54.5	$ 1,068.5	$ 12.8	$ -	$ 1,234.1
Fees from midstream services	8.0	4.8	43.1	28.4	-	-	84.3
	54.6	56.5	97.6	1,096.9	12.8	-	1,318.4
Intersegment revenues							
Sales of commodities	259.7	162.2	-	114.9	-	(536.8)	-
Fees from midstream services	0.3	-	24.6	7.0	-	(31.9)	-
	260.0	162.2	24.6	121.9	-	(568.7)	-
Revenues	$ 314.6	$ 218.7	$ 122.2	$ 1,218.8	$ 12.8	$ (568.7)	$ 1,318.4
Operating margin	$ 53.9	$ 28.0	$ 45.7	$ 26.2	$ 12.8	$ -	$ 166.6
Other financial information:							
Total assets	$ 1,677.2	$ 423.8	$ 925.8	$ 448.8	$ 77.6	$ 113.2	$ 3,666.4
Capital expenditures	$ 46.6	$ 2.6	$ 89.9	$ 0.4	$ -	$ 0.9	$ 140.4

	Six Months Ended June 30, 2013						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 89.2	$ 152.6	$ 78.2	$ 2,278.9	$ 12.3	$ -	$ 2,611.2
Fees from midstream services	42.8	18.7	94.6	72.2	-	-	228.3
	132.0	171.3	172.8	2,351.1	12.3	-	2,839.5
Intersegment revenues							
Sales of commodities	564.0	287.7	1.8	236.2	-	(1,089.7)	-
Fees from midstream services	1.6	-	69.9	12.5	-	(84.0)	-
	565.6	287.7	71.7	248.7	-	(1,173.7)	-
Revenues	$ 697.6	$ 459.0	$ 244.5	$ 2,599.8	$ 12.3	$ (1,173.7)	$ 2,839.5
Operating margin	$ 121.1	$ 40.1	$ 108.6	$ 61.4	$ 12.3	$ -	$ 343.5
Other financial information:							
Total assets	$ 2,950.9	$ 403.9	$ 1,303.6	$ 509.6	$ 28.8	$ 125.8	$ 5,322.6
Capital expenditures	$ 211.2	$ 10.8	$ 217.8	$ 0.7	$ -	$ 2.1	$ 442.6

	Six Months Ended June 30, 2012						
	Field Gathering and Processing	**Coastal Gathering and Processing**	**Logistics Assets**	**Marketing and Distribution**	**Other**	**Corporate and Eliminations**	**Total**
Revenues							
Sales of commodities	$ 92.0	$ 111.5	$ 100.0	$ 2,485.8	$ 14.1	$ -	$ 2,803.4
Fees from midstream services	18.9	8.5	82.0	51.1	-	-	160.5
	110.9	120.0	182.0	2,536.9	14.1	-	2,963.9
Intersegment revenues							
Sales of commodities	577.1	382.2	-	246.8	-	(1,206.1)	-
Fees from midstream services	0.6	0.1	48.7	16.3	-	(65.7)	-
	577.7	382.3	48.7	263.1	-	(1,271.8)	-
Revenues	$ 688.6	$ 502.3	$ 230.7	$ 2,800.0	$ 14.1	$ (1,271.8)	$ 2,963.9
Operating margin	$ 126.9	$ 74.3	$ 88.7	$ 52.4	$ 14.1	$ -	$ 356.4
Other financial information:							
Total assets	$ 1,677.2	$ 423.8	$ 925.8	$ 448.8	$ 77.6	$ 113.2	$ 3,666.4
Capital expenditures	$ 72.8	$ 4.6	$ 150.0	$ 9.5	$ -	$ 1.5	$ 238.4

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Sales of commodities				
Natural gas sales	$ 347.6	$ 188.0	$ 602.8	$ 390.7
NGL sales	896.7	950.7	1,860.3	2,240.9
Condensate sales	33.0	29.0	60.1	58.0
Petroleum products	44.2	54.3	75.5	99.8
Derivative activities	6.0	12.1	12.5	14.0
	1,327.5	1,234.1	2,611.2	2,803.4
Fees from midstream services				
Fractionating and treating fees	31.0	28.6	60.7	55.5
Storage, terminaling, transportation and export fees	47.1	35.4	107.2	65.8
Gathering and processing fees	26.9	9.8	45.4	18.3
Other	9.1	10.5	15.0	20.9
	114.1	84.3	228.3	160.5
Total revenues	$ 1,441.6	$ 1,318.4	$ 2,839.5	$ 2,963.9

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Reconciliation of operating margin to net income:				
Operating margin	$ 169.1	$ 166.6	$ 343.5	$ 356.4
Depreciation and amortization expense	(65.7)	(47.6)	(129.6)	(94.3)
General and administrative expense	(36.1)	(33.5)	(70.3)	(66.4)
Interest expense, net	(31.6)	(29.4)	(63.0)	(58.8)
Income tax expense	(0.9)	(0.8)	(1.8)	(1.8)
Other, net	(2.1)	(0.6)	(0.8)	1.5
Net income	$ 32.7	$ 54.7	$ 78.0	$ 136.6

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, 2012 ("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 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.

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 a leading provider of midstream natural gas, NGLs, terminaling and crude oil gathering services in the United States. 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;
- gathering, storing and terminaling crude oil; and
- storing, terminaling and selling refined petroleum products.

We report our operations in two divisions: (i) 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 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. With the Badlands acquisition on December 31, 2012, this segment's assets now includes the Badlands crude oil and natural gas gathering, terminaling and processing assets in North Dakota. Because the acquisition closed on December 31, 2012, Badlands had no operational impact for 2012. 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, 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, as well as transporting natural gas and NGLs.

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs, including services for exported LPGs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana.

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; providing propane, butane and services to LPG exporters; and (4) marketing natural gas available to us from our 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.

2013 Developments

Badlands Acquisition

On January 1, 2013, we assumed operational control of the Badlands assets and commenced integration activities. These assets are still in a start-up phase. We anticipate rapid growth of volumes and build-out of the Badlands system throughout 2013 and 2014. Badlands operational results are included as part of the Field Gathering and Processing segment.

The Badlands acquisition is subject to a contingent payment of $50 million (the "contingent consideration") if aggregate crude oil gathering volumes exceed certain stipulated monthly thresholds during the period from January 2013 through June 2014. If the threshold is not attained during the contingency period, no payment is owed. Accounting standards require that the contingent consideration be recorded at fair value at the date of acquisition and revalued at subsequent reporting dates during the contingency period. At December 31, 2012, we recorded a $15.3 million accrued liability representing the fair value of this contingent consideration, determined by a probability-based model measuring the likelihood of meeting the thresholds.

Changes in the fair value of this accrued liability are included in earnings and reported as Other income (expense) in the Consolidated Statement of Operations. At June 30, 2013, we re-estimated the contingent consideration to be $9.1 million, a decrease of $6.2 million from the December 31, 2012 valuation. The change in the contingent liability reflects management's updated assessment of the likelihood of meeting the stipulated volumetric thresholds, net of accretion of the discount factor due to the passage of time.

Accounts Receivable Securitization Facility

In January 2013, we entered into a Securitization Facility that provides up to $200 million of borrowing capacity at commercial paper rates plus a margin through January 2014. Under this Securitization Facility, one of our consolidated subsidiaries (TLMT) sells or contributes receivables, without recourse, to another of its consolidated subsidiaries (TRLLC), a special purpose consolidated subsidiary created for the sole purpose of this Securitization Facility. TRLLC, in turn, sells an undivided percentage ownership in the eligible receivables to a third-party financial institution. Receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of TLMT or us. Any excess receivables are eligible to satisfy the claims of creditors of TLMT or us. Total funding under this Securitization Facility as of June 30, 2013 was $125.3 million.

Financing Activities

During the six months ended June 30, 2013, pursuant to sales under our 2012 and 2013 EDAs, we issued 5,971,395 common units representing net proceeds of $227.5 million, received during the six months ended June 30, 2013 and an additional $32.8 million was received in July 2013. Targa contributed $4.0 million to maintain its 2% general partner interest during the six months ended June 30, 2013 and an additional $1.4 million was received in July 2013. Based upon market conditions and our capital needs, at our option, we can sell additional common units up to an aggregate amount of $35.6 million under these agreements.

In April 2013, we filed with the SEC a universal shelf registration statement (the April 2013 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. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the six months ended June 30, 2013.

In May 2013, we privately placed $625.0 million in aggregate principal amount of 4¼% Notes. The 4¼% Notes resulted in approximately $618.1 million of net proceeds, which were used to reduce borrowings under our senior secured revolving credit facility and for general partnership purposes.

In June 2013, we redeemed $100 million of the outstanding 6⅜% Notes at a redemption price of 106.375% plus accrued interest through the redemption date using proceeds from the 2013 EDA. The redemption resulted in a $7.4 million loss on debt redemption, including the write-off of unamortized debt issue costs.

In July 2013, we redeemed the outstanding 11¼% Notes at a price of 105.625% plus accrued interest through July 15, 2013. The redemption resulted in a $7.4 million loss on debt redemption, including the write-off of unamortized notes discounts and unamortized debt issue costs. The loss was recorded in the third quarter 2013.

In July 2013, we filed with the SEC a universal shelf registration statement, the July 2013 Shelf, that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $800 million of debt or equity securities. The July 2013 Shelf expires in August 2016.

Recent Accounting Pronouncements

In January 2013, the FASB issued Accounting Standards Update No. 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* which clarifies that ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities,* applies to financial instruments or derivative transactions accounted for under ASC 815. The amendments require disclosures to present both gross and net amounts of derivative assets and liabilities that are subject to master netting arrangements with counterparties. We currently present our derivative assets and liabilities gross on our statement of financial position. We have provided additional disclosures regarding the gross and net amounts of derivative assets and liabilities in Note 10 in accordance with these new standards updates.

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 crude oil, natural gas, NGLs and condensate we sell, and (ii) the costs associated with conducting our operations, including the costs of crude oil, 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 crude oil, natural gas and NGLs and the volumes of crude oil, 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, based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, is resulting in an increasing percentage of assets that generate fee-based revenues. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering 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, (3) capital expenditures and (4) 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 and crude oil to offset the natural decline of existing volumes from oil and natural 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 crude oil and 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. Our recently acquired assets in the Bakken Shale should allow us to participate in the infrastructure build-out in return for fee-based revenue to gather crude oil or gather and process natural gas, from the wellhead to various takeaway options. There is a significant amount of uncommitted acreage in proximity to our system, which should provide further opportunities to enhance medium and long-term growth in the Bakken Shale.

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 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 crude oil gathering and logistics assets. These volume, recovery and fuel consumption measurements are an important part of our operational efficiency analysis and safety programs.

Operating Expenses

Operating expenses are costs associated with the operation of specific assets. 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.

Capital Expenditures

We closely monitor the capital projects associated with growth and maintenance projects. We analyze return on investment before a capital project is approved, closely monitor the spending throughout the development of the project and evaluate ensuing operational performance versus capital investment economic analysis. We have seen a substantial increase in our total capital spent over the last three years and currently have significant internal growth projects that we closely monitor.

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 Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate and NGLs (2) natural gas and crude oil gathering and service fee revenues and (3) settlement gains and losses on commodity hedges, less product purchases, which consist primarily of producer payments and other natural gas purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees, NGL and natural gas sales, less cost of sales, which consists primarily of NGL and natural gas purchases, transportation costs and changes in inventory valuation.

Operating Margin

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

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.

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 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 redemptions, early debt extinguishments and asset disposals; non-cash risk management activities related to derivative instruments; and changes in the fair value of the Badlands acquisition contingent consideration. 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.

Adjusted EBITDA is a non-GAAP financial measure. 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 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 redemptions, early debt extinguishments and asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs), and changes in the fair value of the Badlands acquisition contingent consideration. 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).

Distributable cash flow is a non-GAAP financial measure. 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. It 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 periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	$ 265.2	$ 243.8	$ 525.6	$ 505.2
Operating expenses	(96.1)	(77.2)	(182.1)	(148.8)
Operating margin	169.1	166.6	343.5	356.4
Depreciation and amortization expenses	(65.7)	(47.6)	(129.6)	(94.3)
General and administrative expenses	(36.1)	(33.5)	(70.3)	(66.4)
Interest expense, net	(31.6)	(29.4)	(63.0)	(58.8)
Income tax expense	(0.9)	(0.8)	(1.8)	(1.8)
Gain (loss) on sale or disposition of assets	(3.9)	-	(3.8)	0.1
Loss on debt redemption and early debt extinguishments	(7.4)	-	(7.4)	-
Change in contingent consideration	6.5	-	6.2	-
Other, net	2.7	(0.6)	4.2	1.4
Targa Resources Partners LP net income	$ 32.7	$ 54.7	$ 78.0	$ 136.6

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$ 5.1	$ 78.3	$ 176.8	$ 225.0
Net income attributable to noncontrolling interests	(6.4)	(7.9)	(12.8)	(19.6)
Interest expense, net (1)	27.6	24.9	55.0	49.7
Loss on debt redemption and early debt extinguishments	(7.4)	-	(7.4)	-
Change in contingent consideration	(6.5)	-	(6.2)	-
Current income tax expense	0.5	0.4	1.0	1.0
Other (2)	5.2	(4.2)	1.2	(9.1)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	90.0	(50.5)	(31.5)	(208.7)
Accounts payable and other liabilities	18.4	81.9	82.7	230.0
Targa Resources Partners LP Adjusted EBITDA	$ 126.5	$ 122.9	$ 258.8	$ 268.3

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $4.0 million and $4.4 million for the three months ended June 30, 2013 and 2012, and $8.0 million and $8.9 million for the six months ended June 30, 2013 and 2012.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$ 26.3	$ 46.8	$ 65.2	$ 117.0
Add:				
Interest expense, net	31.6	29.4	63.0	58.8
Income tax expense	0.9	0.8	1.8	1.8
Depreciation and amortization expenses	65.7	47.6	129.6	94.3
Loss on sale or disposition of assets	3.9	-	3.8	-
Loss on debt redemption and early debt extinguishments	7.4	-	7.4	-
Change in contingent consideration	(6.5)	-	(6.2)	-
Risk management activities	0.2	1.2	0.1	2.2
Noncontrolling interests adjustment (1)	(3.0)	(2.9)	(5.9)	(5.8)
Targa Resources Partners LP Adjusted EBITDA	$ 126.5	$ 122.9	$ 258.8	$ 268.3

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(In millions)			
Reconciliation of net income attributable to Targa Resources Partners LP to distributable cash flow:				
Net income attributable to Targa Resources Partners LP	$ 26.3	$ 46.8	$ 65.2	$ 117.0
Depreciation and amortization expenses	65.7	47.6	129.6	94.3
Deferred income tax expense	0.4	0.4	0.8	0.8
Amortization in interest expense	4.0	4.4	8.0	8.9
Loss on debt redemption and early debt extinguishment	7.4	-	7.4	-
Change in contingent consideration	(6.5)	-	(6.2)	-
Loss on sale or disposition of assets	3.9	-	3.8	-
Risk management activities	0.2	1.2	0.1	2.2
Maintenance capital expenditures	(21.8)	(15.5)	(43.4)	(31.9)
Other (1)	(0.6)	(0.4)	(0.6)	(1.1)
Targa Resources Partners LP distributable cash flow	$ 79.0	$ 84.5	$ 164.7	$ 190.2

(1) Includes reimbursements of certain environmental maintenance capital expenditures by Targa, 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:

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	2013 vs. 2012		Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	2013 vs. 2012	
	(In millions, except operating statistics and price amounts)							
Revenues	$ 1,441.6	$ 1,318.4	$ 123.2	9%	$ 2,839.5	$ 2,963.9	$ (124.4)	(4%)
Product purchases	1,176.4	1,074.6	101.8	9%	2,313.9	2,458.7	(144.8)	(6%)
Gross margin (1)	265.2	243.8	21.4	9%	525.6	505.2	20.4	4%
Operating expenses	96.1	77.2	18.9	24%	182.1	148.8	33.3	22%
Operating margin (2)	169.1	166.6	2.5	2%	343.5	356.4	(12.9)	(4%)
Depreciation and amortization expenses	65.7	47.6	18.1	38%	129.6	94.3	35.3	37%
General and administrative expenses	36.1	33.5	2.6	8%	70.3	66.4	3.9	6%
Other operating (income) expense	4.1	-	4.1	-	4.2	(0.1)	4.3	-
Income from operations	63.2	85.5	(22.3)	(26%)	139.4	195.8	(56.4)	(29%)
Interest expense, net	(31.6)	(29.4)	(2.2)	7%	(63.0)	(58.8)	(4.2)	7%
Equity earnings	2.9	(0.2)	3.1	NM	4.5	1.9	2.6	NM
Loss on debt redemption	(7.4)	-	(7.4)	-	(7.4)	-	(7.4)	-
Other	6.5	(0.4)	6.9	NM	6.3	(0.5)	6.8	NM
Income tax expense	(0.9)	(0.8)	(0.1)	(13%)	(1.8)	(1.8)	-	-
Net income	32.7	54.7	(22.0)	(40%)	78.0	136.6	(58.6)	(43%)
Less: Net income attributable to noncontrolling interests	6.4	7.9	(1.5)	(19%)	12.8	19.6	(6.8)	(35%)
Net income attributable to Targa Resources Partners LP	$ 26.3	$ 46.8	$ (20.5)	(44%)	$ 65.2	$ 117.0	$ (51.8)	(44%)
Financial and operating data:								
Financial data:								
Adjusted EBITDA (3)	$ 126.5	$ 122.9	$ 3.6	3%	$ 258.8	$ 268.3	$ (9.5)	(4%)
Distributable cash flow (4)	79.0	84.5	(5.5)	(7%)	164.7	190.2	(25.5)	(13%)
Capital expenditures	235.7	140.4	95.3	68%	442.6	238.4	204.2	86%
Operating data:								
Crude oil gathered, MBbl/d	38.3	-	38.3	-	34.9	-	34.9	-
Plant natural gas inlet, MMcf/d (5)(6)	2,072.2	2,083.0	(10.8)	(1%)	2,075.6	2,157.8	(82.2)	(4%)
Gross NGL production, MBbl/d	131.2	124.0	7.2	6%	132.3	128.1	4.2	3%
Export volumes, MBbl/d	41.2	28.0	13.2	47%	43.0	25.1	17.9	71%
Natural gas sales, BBtu/d (6)	953.1	930.3	22.8	2%	901.7	895.4	6.3	1%
NGL sales, MBbl/d	282.7	270.3	12.4	5%	282.0	274.7	7.3	3%
Condensate sales, MBbl/d	4.0	3.7	0.3	9%	3.7	3.4	0.3	10%

(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 debt redemptions, early debt extinguishments and asset disposals, non-cash risk management activities related to derivative instruments and changes in the fair value of the Badlands acquisition contingent consideration. 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, debt redemptions, early debt extinguishments, asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs) and changes in the fair value of the Badlands acquisition contingent consideration. 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 June 30, 2013 Compared to Three Months Ended June 30, 2012

The increase in revenues reflected higher realized prices on natural gas and condensate ($148.8 million), higher commodity sales volumes ($50.7 million) and higher fee-based and other revenues ($19.8 million). Partially offsetting these favorable factors were lower realized prices on NGLs ($96.1 million).

The increase in consolidated gross margin was driven by volume expansions and higher natural gas price in our Field Gathering and Processing segment and higher fractionation fees and increased exports activities in our Logistics and Marketing division. Offsetting these favorable factors were the effects of lower NGL prices and lower system volumes in our Coastal Gathering and Processing segment. Logistics margins were partially constrained by the planned maintenance and inspection turnaround at Cedar Bayou Fractionators (CBF). Higher operating expenses were driven by system expansions in Field Gathering and Processing, growth projects in Logistics, the Badlands acquisition and higher labor and maintenance costs. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in the components of gross and operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the Badlands acquisition, system expansions and other assets placed in service during the last twelve months.

General and administrative expenses increased primarily due to higher compensation and benefits.

The increase in interest expense reflects higher borrowing levels to fund our business expansion ($8.0 million), offset by higher interest capitalized on major capital projects ($5.9 million).

The June 2013 redemption of $100 million of the outstanding 6⅜% Notes at a redemption price of 106.375% plus accrued interest resulted in a $7.4 million loss, consisting of a premium paid of $6.4 million and the write-off of $1.0 million of unamortized debt issue costs.

The decrease in net income attributable to noncontrolling interests reflects the impact of lower earnings at our non-wholly owned Upstream consolidated subsidiaries, primarily at our Versado and VESCO joint ventures, which were affected by operational issues.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

The decrease in revenues reflects lower realized prices, especially during the first quarter of 2013, on NGLs ($418.2 million), which were partially offset by the impact of higher realized prices on natural gas and condensate ($197.5 million), the impact of higher commodity volumes ($51.6 million) and higher fee-based and other revenues ($44.7 million).

The increase in consolidated gross margin for the six months was driven by the same factors as discussed above for the three months. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in the components of gross and operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the Badlands acquisition, system expansions and other assets placed in service during the last twelve months.

General and administrative expenses increased primarily due to compensation and benefits.

The increase in interest expense reflects higher borrowing levels to fund our business expansion ($11.8 million) and higher effective interest rates ($2.6 million), offset by higher interest capitalized on major capital projects ($10.2 million).

The June 2013 6⅜% Notes redemption noted above resulted in a $7.4 million loss on debt redemption.

The decrease in net income attributable to noncontrolling interests reflects the impact of lower earnings at our non-wholly owned Upstream consolidated subsidiaries, primarily at our Versado and VESCO joint ventures, which were affected by operational issues.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Total
Three Months Ended:			(In millions)			
June 30, 2013	$ 67.3	$ 16.7	$ 52.1	$ 27.4	$ 5.6	$ 169.1
June 30, 2012	53.9	28.0	45.7	26.2	12.8	166.6
Six Months Ended:						
June 30, 2013	$ 121.1	$ 40.1	$ 108.6	$ 61.4	$ 12.3	$ 343.5
June 30, 2012	126.9	74.3	88.7	52.4	14.1	356.4

Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	2013 vs. 2012		Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	2013 vs. 2012	
				($ in millions)				
Gross margin	$ 110.2	$ 85.0	$ 25.2	30%	$ 201.7	$ 187.3	$ 14.4	8%
Operating expenses	42.9	31.1	11.8	38%	80.6	60.4	20.2	33%
Operating margin	$ 67.3	$ 53.9	$ 13.4	25%	$ 121.1	$ 126.9	$ (5.8)	(5%)
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Sand Hills	162.4	130.6	31.8	24%	157.4	138.2	19.2	14%
SAOU	155.1	121.9	33.2	27%	147.2	118.6	28.6	24%
North Texas System	290.8	242.7	48.1	20%	275.9	233.5	42.4	18%
Versado	170.8	169.9	0.9	1%	165.8	169.9	(4.1)	(2%)
Badlands	14.1	-	14.1	-	15.0	-	15.0	-
	793.2	665.1	128.1	19%	761.3	660.2	101.1	15%
Gross NGL production, MBbl/d								
Sand Hills	17.5	15.4	2.1	14%	17.5	16.2	1.3	8%
SAOU	22.7	18.9	3.8	20%	21.7	18.5	3.2	17%
North Texas System	32.0	26.8	5.2	19%	30.5	25.8	4.7	18%
Versado	20.6	20.0	0.6	3%	20.0	19.6	0.4	2%
Badlands	1.8	-	1.8	-	1.7	-	1.7	-
	94.6	81.1	13.5	17%	91.4	80.1	11.3	14%
Crude oil gathered, MBbl/d	38.3	-	38.3	-	34.9	-	34.9	-
Natural gas sales, BBtu/d (3)	379.1	312.6	66.5	21%	359.3	313.0	46.3	15%
NGL sales, MBbl/d	67.3	67.5	(0.2)	0%	69.0	66.2	2.8	4%
Condensate sales, MBbl/d	3.6	3.5	0.1	4%	3.3	3.2	0.1	3%
Average realized prices (4):								
Natural gas, $/MMBtu	3.89	2.02	1.87	93%	3.53	2.29	1.24	54%
NGL, $/gal	0.69	0.86	(0.17)	(20%)	0.71	0.96	(0.25)	(26%)
Condensate, $/Bbl	90.58	86.51	4.07	5%	88.40	92.34	(3.94)	(4%)

(1) Segment operating statistics include the effect of intersegment amounts, 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 June 30, 2013 Compared to Three Months Ended June 30, 2012

The increase in gross margin was primarily due to higher throughput volumes and higher natural gas prices partially offset by lower NGL sales prices. The increase in plant inlet volumes was largely attributable to new well connects across each of our areas of operations. At the same time, volumes at Sand Hills and Versado were constrained by operational issues. NGL sales were flat, impacted by the planned partial curtailment of CBF in May and June 2013 (see Logistics Assets discussion). The planned partial curtailment of CBF also resulted in a temporary build of y-grade inventory, primarily for our third party producer customers, is expected to be fractionated during the third and fourth quarters.

The increase in operating expenses was primarily due to the addition of Badlands, additional compression related expenses due to increased volumes, system expansions and higher system maintenance and repair costs.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

The six month results were impacted by the same factors as discussed above for the three month comparison of 2013 to 2012.

Coastal Gathering and Processing

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
				($ in millions)				
Gross margin	$ 28.6	$ 38.8	$ (10.2)	(26%)	$ 62.6	$ 95.5	$ (32.9)	(34%)
Operating expenses	11.9	10.8	1.1	10%	22.5	21.2	1.3	6%
Operating margin	$ 16.7	$ 28.0	$ (11.3)	(40%)	$ 40.1	$ 74.3	$ (34.2)	(46%)
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
LOU (4)	317.7	214.7	103.0	48%	329.5	204.8	124.7	61%
Coastal Straddles	468.0	760.9	(292.9)	(38%)	471.3	800.2	(328.9)	(41%)
VESCO	493.3	442.3	51.0	12%	513.6	492.6	21.0	4%
	1,279.0	1,417.9	(138.9)	(10%)	1,314.4	1,497.6	(183.2)	(12%)
Gross NGL production, MBbl/d								
LOU	8.4	8.2	0.2	2%	8.7	8.2	0.5	6%
Coastal Straddles	13.1	15.8	(2.7)	(17%)	13.3	16.7	(3.4)	(21%)
VESCO	15.2	18.9	(3.7)	(20%)	19.0	23.1	(4.1)	(18%)
	36.7	42.9	(6.2)	(15%)	41.0	48.0	(7.0)	(15%)
Natural gas sales, BBtu/d (3)	285.3	315.1	(29.8)	(9%)	280.2	298.5	(18.3)	(6%)
NGL sales, MBbl/d	35.3	40.7	(5.4)	(13%)	38.3	44.0	(5.7)	(13%)
Condensate sales, MBbl/d	0.3	0.2	0.1	63%	0.4	0.2	0.2	97%
Average realized prices:								
Natural gas, $/MMBtu	4.09	2.27	1.82	80%	3.78	2.43	1.35	56%
NGL, $/gal	0.81	0.95	(0.14)	(14%)	0.83	1.06	(0.23)	(22%)
Condensate, $/Bbl	102.63	91.40	11.23	12%	107.19	111.64	(4.45)	(4%)

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume 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) Includes volumes from the Big Lake processing plant acquired in July 2012.

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012

The decrease in gross margin was primarily due to lower NGL 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, the impact of the Yscloskey, Calumet and other third-party plant shutdowns and operational issues at VESCO and LOU. This volume decrease was partially offset by the addition of the Big Lake plant. The operational issues at VESCO included the impact of damage to one of the two third-party pipelines that provide NGL takeaway capacity for VESCO that constrained NGL production until repairs were completed in June. Lower natural gas sales volumes reflected decreased sales to other reportable segments for resale partially offset by an increase in demand from industrial customers.

The increase in operating expenses was primarily due to higher system maintenance and repair costs at LOU and Yscloskey mothballing expenses.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

The six month results were impacted by the same factors as discussed above for the three month comparison of 2013 to 2012.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	($ in millions)							
Gross margin	$ 84.7	$ 69.1	$ 15.6	23%	$ 171.3	$ 133.5	$ 37.8	28%
Operating expenses	32.6	23.4	9.2	39%	62.7	44.8	17.9	40%
Operating margin	$ 52.1	$ 45.7	$ 6.4	14%	$ 108.6	$ 88.7	$ 19.9	22%
Operating statistics (1):								
Fractionation volumes, MBbl/d	256.6	311.3	(54.7)	(18%)	257.3	302.5	(45.2)	(15%)
LSNG treating volumes, MBbl/d	19.4	27.1	(7.7)	(28%)	22.6	23.1	(0.5)	(2%)
Benzene treating volumes, MBbl/d	16.9	23.7	(6.8)	(29%)	18.8	20.4	(1.5)	(7%)

(1) Segment operating statistics include intersegment amounts, 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 June 30, 2013 Compared to Three Months Ended June 30, 2012

The increase in gross margin reflects higher revenues from all logistics activities except for treating. Higher fractionation fees more than offset the impact of partially curtailed fractionation volumes associated with the planned maintenance turnaround at CBF. Included in the increase in fractionation gross margin is the impact of higher fuel prices, which pass through to operating expenses. The CBF planned maintenance, which started in May 2013 and was completed in July 2013, primarily addresses Occupational Safety and Health Administration ("OSHA") Process Safety Management Standards and CBF's mechanical integrity programs. Export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 41 MBbl/d for the three months ended June 30, 2013, compared to 28 MBbl/d for the same period last year. Export rates were also higher. Storage revenues were higher due to increased rates and new customers. Treating revenues decreased due to reduced market demand. Petroleum Logistics terminaling gross margin improved as a result of increased crude oil throughput, the 2013 start-up of a renewable fuels project, and improved margins.

The increase in operating expenses primarily reflects higher fuel and power prices (which have a corresponding impact on fractionating and treating revenues), expenses related to the commissioning of Train Four at CBF, and increased maintenance costs, partially offset by higher system product gains.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

The six month results were impacted by the same factors as discussed above for the three month comparison of 2013 to 2012.

Marketing and Distribution

	Three Months Ended June 30,		2013 vs. 2012		Six Months Ended June 30,		2013 vs. 2012	
	2013	2012			2013	2012		
	($ in millions)							
Gross margin	$ 37.2	$ 35.4	$ 1.8	5%	$ 82.0	$ 70.8	$ 11.2	16%
Operating expenses	9.8	9.2	0.6	7%	20.6	18.4	2.2	12%
Operating margin	$ 27.4	$ 26.2	$ 1.2	5%	$ 61.4	$ 52.4	$ 9.0	17%
Operating statistics (1):								
NGL sales, MBbl/d	282.9	274.4	8.5	3%	283.3	278.5	4.8	2%
Average realized prices:								
NGL realized price, $/gal	0.84	0.92	(0.08)	(9%)	0.88	1.07	(0.19)	(18%)

(1) Segment operating statistics include intersegment amounts, 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 June 30, 2013 Compared to Three Months Ended June 30, 2012

Gross margin increased primarily due to higher LPG export activity (which benefited both the Logistics Assets and Marketing and Distribution segments), higher truck and barge utilization and higher wholesale terminal margins, partially offset by lower marketing fees.

Operating expenses increased primarily due to higher truck utilization and increased storage operating costs.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

The six month results were impacted by the same factors as discussed above for the three month comparison of 2013 to 2012.

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
			(In millions)			
Gross margin	$ 5.6	$ 12.8	$ (7.2)	$ 12.3	$ 14.1	$ (1.8)
Operating margin	$ 5.6	$ 12.8	$ (7.2)	$ 12.3	$ 14.1	$ (1.8)

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 their percent of proceeds or liquids processing arrangements by entering into derivative instruments.

Table of Contents

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	2013 vs. 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	2013 vs. 2012
	(In millions)					
Natural gas	$ 1.0	$ 10.4	$ (9.4)	$ 4.3	$ 19.0	$ (14.7)
NGL	4.5	3.0	1.5	8.1	(2.6)	10.7
Crude oil	0.1	(0.6)	0.7	(0.1)	(2.3)	2.2
	$ 5.6	$ 12.8	$ (7.2)	$ 12.3	$ 14.1	$ (1.8)

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.

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) and 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 the TRP Revolver, borrowings under the Securitization Facility, the issuance of additional common units and access to debt markets. The capital markets continue to experience volatility. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. We continually monitor our liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

As of July 29, 2013, our liquidity consisted of the following:

	July 29, 2013
	(In millions)
Cash on hand	$ 91.7
Total availability under the TRP Revolver	1,200.0
Total availability under the Securitization Facility	114.1
	1,405.8
Less:	
Outstanding borrowings under the TRP Revolver	(368.0)
Outstanding borrowings under the Securitization Facility	(114.1)
Outstanding letters of credit under the TRP Revolver	(51.2)
Total liquidity	$ 872.5

We may issue additional equity or debt securities under our outstanding shelf registration statements to assist us in meeting future liquidity and capital spending requirements (see Notes 8 and 9).

During the six months ended June 30, 2013, pursuant to the 2012 Shelf, we issued 5,971,395 common units representing net proceeds of $227.5 million, received during the six months ended June 30, 2013 and an additional $32.8 million was received in July 2013. Targa contributed $4.0 million to maintain its 2% general partner interest during the six months ended June 30, 2013 and an additional $1.4 million was received in July 2013. Based upon market conditions and our capital needs, at our option, we have the ability to sell additional common units up to an aggregate amount of $35.6 million under the 2012 Shelf.

In April 2013, we filed with the SEC a universal shelf registration statement, the April 2013 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. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the six months ended June 30, 2013.

In July 2013, we filed with the SEC a universal shelf registration statement (the July 2013 Shelf) that, subject to effectiveness at the time of use, allowing us to issue up to an aggregate of $800 million of debt or equity securities. The July 2013 Shelf expires in August 2016.

In July 2013, we redeemed the outstanding 11¼% Notes for $80.9 million, including accrued interest.

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 entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas equity volumes through 2016 and our NGL and condensate equity volumes through 2014. 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 asset position of $22.2 million at December 31, 2012 to a net asset position of $23.2 million at June 30, 2013. Aggregate forward prices for commodities are below the fixed prices we currently expect to receive on those derivative contracts, creating this 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 six months ended June 30, 2013, our working capital increased $44.9 million, primarily due to an increase of inventory in advance of the start-up of our international export project coming on-line in the third quarter of this year, increased materials and supply inventory for our Badlands operations and a decrease in affiliate payables due to timing of reimbursements between Targa and us.

Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow, borrowings available under the TRP Revolver and the Securitization Facility 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 time, 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. As of June 30, 2013, we had $47.9 million in letters of credit outstanding.

Cash Flow

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

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	2013 vs. 2012
	(In millions)		
Net cash provided by (used in):			
Operating activities	$ 176.8	$ 225.0	$ (48.2)
Investing activities	(455.0)	(250.8)	(204.2)
Financing activities	282.9	59.7	223.2

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:

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	2013 vs. 2012
	(In millions)		
Cash flows from operating activities:			
Cash received from customers	$ 2,900.3	$ 3,173.0	$ (272.7)
Cash received from (paid to) derivative counterparties	12.3	16.6	(4.3)
Cash outlays for:			
Product purchases	(2,421.8)	(2,704.8)	283.0
Operating expenses	(175.7)	(142.9)	(32.8)
General and administrative expenses	(87.7)	(76.7)	(11.0)
Cash distributions from equity investment	-	1.9	(1.9)
Interest paid, net of amounts capitalized (1)	(54.6)	(39.4)	(15.2)
Income taxes paid	(2.3)	(2.0)	(0.3)
Other cash receipts (payments)	6.3	(0.7)	7.0
Net cash provided by operating activities	$ 176.8	$ 225.0	$ (48.2)

(1) Net of capitalized interest paid of $14.8 million and $4.5 million included in investing activities for the six months ended June 30, 2013 and 2012.

Lower liquids prices were the primary factor in the changes in cash from customers, cash from derivative contracts, and cash paid for purchases. The impact of lower liquid prices on product purchases was partially offset by higher natural gas prices paid to producers. For the six months ended June 30, 2013 and 2012, our derivative settlements were a net cash inflow. Other changes in operating cash flows are consistent with explanations included in our discussion of the results of operations.

Cash Flow from Investing Activities

The increase in net cash used in investing activities was due to an increase in current capital expansion projects of $195.5 million, increased maintenance capital expenditures of $10.6 million, an increase in other of $11.8 million, which is primarily related to materials and supply inventory purchases for our Badlands operations, offset by the absence of capital calls at our unconsolidated affiliates in 2013 compared to $13.7 million in 2012.

Cash Flow from Financing Activities

The increase in net cash provided by financing activities was primarily due to an increase in long-term debt net borrowings of $203.4 million, an increase in proceeds from the issuance of common units of $66.8 million, partially offset by an increase in distributions to owners of $50.8 million.

Our primary financing activities that occurred during the six months ended June 30, 2013 were:

- $395.0 million related to net repayments under credit facility;
- $231.2 million from the sale of common units under the 2012 and 2013 EDAs;
- $4.0 million related general partner contributions to maintain 2% general partner ownership;
- $125.3 million of net borrowings under the Securitization Facility;
- $618.1 million of new debt from the issuance of 4¼% Notes; and
- $106.4 million related to the redemption of $100 million face value of 6⅜% Senior Notes.

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 8 and Note 9 of the "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 June 30, 2013, such annual minimum amount would have been approximately $143.2 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 August 2013 for the second quarter of 2013 is $0.715 per limited partner unit.

The following table details the distributions declared and/or paid for the six months ended June 30, 2013:

		Distributions				
		Limited Partners	General Partner			Distributions per limited partner unit
Three Months Ended	Date Paid or to be Paid	Common	Incentive	2%	Total	
		(In millions, except per unit amounts)				
June 30, 2013	August 14, 2013	$ 75.8	$ 24.6	$ 2.0	$ 102.4	$ 0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	0.6975
December 31, 2012	February 14, 2013	69.0	20.1	1.8	90.9	0.6800

Capital Requirements

Our capital requirements relate to capital expenditures, which are classified as expansion expenditures, maintenance expenditures or business acquisitions. 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 are worn, obsolete or completing their useful life, and expenditures to remain in compliance with environmental laws and regulations.

	Six Months Ended June 30,	
	2013	**2012**
Capital expenditures :	**(In millions)**	
Expansion (1)	$ 399.2	$ 206.5
Maintenance	43.4	31.9
Gross additions to property, plant and equipment	442.6	238.4
Change in capital project payables and accruals	1.9	-
Cash outlays for capital projects	$ 444.5	$ 238.4

(1) Excludes our investment in Gulf Coast Fractionators, which is accounted for as an equity investment. Cash calls for expansion are reflected in Investment in unconsolidated affiliate in cash flows from investing activities on our Consolidated Statements of Cash Flows in our Consolidated Financial Statements.

We estimate that our total growth capital expenditures for 2013 will be approximately $1.0 billion on a gross basis, and maintenance capital expenditures net to our interest will be approximately $85 million. 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. Future expansion capital expenditures may vary significantly based on investment opportunities. We expect to fund future capital expenditures with funds generated from our operations, borrowings under the TRP Revolver and proceeds from issuances of additional equity 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. During the six months ended June 30, 2013, we established our policies related to the amortization and useful lives of the intangible assets related to the Badlands acquisition.

Intangible assets arose from producer dedications under long-term contracts and customer relationships associated with business acquisitions. The fair value of these acquired intangible assets was determined at the date of acquisitions based on the present value of estimated future cash flows. Amortization expense attributable to these assets is recorded in a manner that closely resembles the expected pattern that we benefit from services provided to customers, which results in an acceleration of amortization expense versus the straight-line method.

Off-Balance Sheet Arrangements

We have no material off-balance sheet arrangements as defined by the Securities and Exchange Commission.

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 significant portion 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 our commodity risk management activities is to manage the exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of June 30, 2013, we have hedged the commodity prices 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 results from percent of proceeds processing arrangements. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, in which we hedge incrementally lower percentages of expected equity volumes. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (or 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. The 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. The 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. During the three months ended June 30, 2013 and 2012, our operating revenues were increased by net hedge adjustments on commodity derivative contracts of $5.6 million and $12.8 million. During the six months ended June 30, 2013 and 2012, our operating revenues were increased by net hedge adjustments on commodity derivative contracts of $12.3 million and $14.1 million.

As of June 30, 2013, the following derivative instruments, which are designated as hedging instruments, will settle during the years ending below:

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu/d 2013	2014	2015	2016	Fair Value (in millions)
Swap	IF-WAHA	4.45	18,354	-	-	-	$ 3.1
Swap	IF-WAHA	3.86	-	14,780	-	-	0.3
Swap	IF-WAHA	4.05	-	-	8,736	-	-
Swap	IF-WAHA	4.25	-	-	-	4,436	-
Total Swaps			18,354	14,780	8,736	4,436	
Swap	IF-PB	4.50	14,871	-	-	-	2.8
Swap	IF-PB	3.80	-	11,966	-	-	0.3
Swap	IF-PB	4.02	-	-	7,076	-	0.2
Swap	IF-PB	4.22	-	-	-	3,608	0.1
Total Swaps			14,871	11,966	7,076	3,608	
Swap	IF-NGPL MC	4.14	7,865	-	-	-	0.9
Swap	IF-NGPL MC	3.58	-	6,304	-	-	(0.3)
Swap	IF-NGPL MC	3.88	-	-	3,739	-	-
Swap	IF-NGPL MC	4.13	-	-	-	1,956	0.1
Total Swaps			7,865	6,304	3,739	1,956	
Total			41,090	33,050	19,551	10,000	
							$ 7.5

NGL

Instrument Type	Index	Price $/Gal	Bbl/d 2013	2014	Fair Value (in millions)
Swap	OPIS-MB	1.05	5,650	-	$ 11.2
Swap	OPIS-MB	1.21	-	1,000	5.6
Total			5,650	1,000	
					$ 16.8

Condensate

Instrument Type	Index	Price $/Bbl	Bbl/d 2013	2014	Fair Value (in millions)
Swap	NY-WTI	93.23	2,045	-	$ (0.7)
Swap	NY-WTI	89.80	-	1,450	(0.1)
Total			2,045	1,450	
					$ (0.8)

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 11 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 the TRP Revolver and the Securitization Facility. As of June 30, 2013, we do not have any interest rate hedges. However, we may in the future enter into interest rate hedges intended to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRP Revolver and the Securitization Facility will also increase. As of June 30, 2013, we had $350.3 million in variable rate borrowings under the TRP Revolver and the Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense by $3.5 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 June 30, 2013, affiliates of Wells Fargo Bank N.A. ("Wells Fargo"), Bank of America Merrill Lynch ("BAML"), Barclays PLC ("Barclays") and Natixis Securities Americas LLC ("Natixis") accounted for 30%, 23%, 17% and 11% of our counterparty credit exposure related to commodity derivative instruments. Wells Fargo, BAML, Barclays and Natixis 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.

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable, annual operating income would decrease by $4.4 million in the year of the assessment.

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 June 30, 2013, 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 June 30, 2013 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 12 – 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.

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	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)).
3.4	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)).
3.5	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)).
3.6	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Indenture dated as of May 14, 2013 among the Issuers and the Guarantors 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 May 14, 2013 (File No. 001-33303)).
4.2	Registration Rights Agreement dated as of May 14, 2013 among the Issuers, the Guarantors and Wells Fargo Securities, LLC, Barclays Capital Inc., Deutsche Bank Securities Inc., J.P. Morgan Securities LLC and RBC Capital Markets, LLC, 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 May 14, 2013 (File No. 001-33303)).
10.1	Targa Resources Partners LP Performance Unit Grant Agreement (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.2	Targa Resources Partners LP Amendment to Outstanding Performance Units (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.3	First Amendment to the Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.4	Targa Resources Partners LP Performance Unit Grant Agreement under the Targa Resources Corp. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).

10.5	Targa Resources Corp. Amendment to Targa Resources Partner LP Outstanding Performance Units (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
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: August 2, 2013

By: */s/ Matthew J. Meloy*
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Authorized Officer and Principal Financial Officer)

Exhibit 12.1

Targa Resources Partners, LP
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,					Six Months Ended June 30,	
	2012	**2011**	**2010**	**2009**	**2008**	**2013**	**2012**
Pre-tax income (loss) from continuing operations	$ 207.4	$ 249.8	$ 138.0	$ 8.4	$ 238.1	$ 79.8	$ 138.5
Fixed charges:							
Interest expense and amortization of debt issuance costs	116.8	107.7	110.9	159.8	156.1	63.0	58.8
Capitalized interest	13.6	3.4	1.3	0.7	0.6	14.8	4.5
Operating lease payments	5.4	4.7	4.6	4.5	4.8	3.8	2.2
Total fixed charges	135.8	115.8	116.8	165.0	161.5	81.6	65.5
Amortization of capitalized interest	0.7	0.2	0.1	0.1	0.1	0.7	0.2
Equity earnings in unconsolidated investment	(1.9)	(8.8)	(5.4)	(5.0)	(14.0)	(4.5)	(1.9)
Distributions from unconsolidated investment	2.3	8.3	8.7	5.1	4.6	-	2.3
Capitalized interest	(13.6)	(3.4)	(1.3)	(0.7)	(0.6)	(14.8)	(4.5)
Pre-tax income from continuing operations plus fixed charges	$ 330.6	$ 361.9	$ 256.9	$ 172.9	$ 389.7	$ 142.7	$ 200.1
Ratio of earnings to fixed charges	2.4	3.1	2.2	1.0	2.4	1.8	3.1
Deficiency	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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: August 2, 2013

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: August 2, 2013

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)

Exhibit 32.1

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

In connection with the Quarterly Report on Form 10-Q of Targa Resources Partners LP (the "Partnership") for the three months ended June 30, 2013 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: August 2, 2013

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 June 30, 2013 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: August 2, 2013

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.