Targa Resources Corp.
Form 10-Q
August 02, 2013

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

FORM 10-Q

þ 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

¨ 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: 001-34991

TARGA RESOURCES CORP.
(Exact name of registrant as specified in its charter)

Delaware	20-3701075
(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 R No £

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

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

Large accelerated filer R Accelerated filer £ Non-accelerated filer £ Smaller reporting company £
(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 £ No R.

As of July 26, 2013, there were 42,331,487 shares of the registrant’s common stock, $0.001 par value, outstanding.

PART I—FINANCIAL INFORMATION

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, other than Targa Resources Partners LP (the "Partnership"), collectively "we," "us," "Targa," "TRC," or the "Company") 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 statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, by the use of forward-looking statements, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "pot "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:

- the Partnership's and 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 the Partnership's transactions;
- the Partnership's 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 the Partnership's services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- the Partnership's ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around the Partnership's assets, its success in connecting natural gas supplies to its gathering and processing systems, oil supplies to its gathering systems and NGL supplies to its logistics and marketing facilities and the Partnership's success in connecting its facilities to transportation and markets;
- the Partnership's and 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”).

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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

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	June 30, 2013	December 31, 2012
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$82.9	$76.3
Trade receivables, net of allowances of $0.9 million and $0.9 million	435.8	514.9
Inventories	138.3	99.4
Assets from risk management activities	23.2	29.3
Other current assets	17.7	13.4
Total current assets	697.9	733.3
Property, plant and equipment	5,166.8	4,708.0
Accumulated depreciation	(1,283.4)	(1,170.0)
Property, plant and equipment, net	3,883.4	3,538.0
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	95.5	94.7
Total assets	$5,407.1	$5,105.0
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$597.4	$679.0
Deferred income taxes	7.4	0.2
Liabilities from risk management activities	3.8	7.4
Total current liabilities	608.6	686.6
Long-term debt	2,728.0	2,475.3
Long-term liabilities from risk management activities	1.8	4.8
Deferred income taxes	125.0	131.2
Other long-term liabilities	62.4	53.7
Commitments and contingencies (see Note 14)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300,000,000 shares authorized, 42,529,218 shares issued and 42,331,487 shares outstanding as of June 30, 2013, and 42,492,233 shares issued and 42,294,502 shares outstanding as of December 31, 2012)	-	-
Preferred stock ($0.001 par value, 100,000,000 shares authorized, no shares issued and outstanding as of June 30, 2013 and December 31, 2012)	-	-

Additional paid-in capital	131.6	184.4
Accumulated deficit	(3.7)	(32.0)
Accumulated other comprehensive income	1.7	1.2
Treasury stock, at cost (197,731 shares as of June 30, 2013 and as of December 31, 2012)	(9.5)	(9.5)
Total Targa Resources Corp. stockholders' equity	120.1	144.1
Noncontrolling interests in subsidiaries	1,761.2	1,609.3
Total owners' equity	1,881.3	1,753.4
Total liabilities and owners' equity	$5,407.1	$5,105.0

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(Unaudited)			
	(In millions, except per share amounts)			
Revenues	$1,441.6	$1,319.1	$2,839.4	$2,964.9
Costs and expenses:				
Product purchases	1,176.4	1,074.6	2,313.9	2,458.8
Operating expenses	96.1	77.3	182.2	148.9
Depreciation and amortization expenses	65.7	48.3	129.7	95.7
General and administrative expenses	38.4	35.7	74.6	70.8
Other operating (income) expense	4.1	-	4.2	(0.1)
Income from operations	60.9	83.2	134.8	190.8
Other income (expense):				
Interest expense, net	(32.4)	(30.5)	(64.5)	(61.0)
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	(0.3)
Income before income taxes	30.5	52.1	73.7	131.4
Income tax expense:				
Current	(7.6)	(7.4)	(16.8)	(16.1)
Deferred	(0.4)	(1.2)	(0.7)	(2.7)
	(8.0)	(8.6)	(17.5)	(18.8)
Net income	22.5	43.5	56.2	112.6
Less: Net income attributable to noncontrolling interests	7.5	34.9	27.9	94.4
Net income available to common shareholders	$15.0	$8.6	$28.3	$18.2
Net income available per common share - basic	$0.36	$0.21	$0.68	$0.44
Net income available per common share - diluted	$0.36	$0.21	$0.67	$0.44
Weighted average shares outstanding - basic	41.6	41.0	41.6	41.0
Weighted average shares outstanding - diluted	42.1	41.9	42.0	41.8

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
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 attributable to Targa Resources Corp.			$15.0			$8.6
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$3.0	$ (1.1)	1.9	$12.7	$ (5.2)	7.5
Settlements reclassified to revenues	(0.8)	0.3	(0.5)	(2.9)	1.2	(1.7)
Interest rate swaps:						
Settlements reclassified to interest expense, net	0.3	(0.1)	0.2	0.3	(0.1)	0.2
Other comprehensive income (loss) attributable to Targa Resources Corp.	$2.5	$ (0.9)	1.6	$10.1	$ (4.1)	6.0
Comprehensive income attributable to Targa Resources Corp.			$16.6			$14.6
Net income attributable to noncontrolling interests			$7.5			$34.9
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	$18.2	$ -	18.2	$65.0	$ (0.4)	64.6
Settlements reclassified to revenues	(5.1)	-	(5.1)	(10.9)	0.1	(10.8)
Interest rate swaps:						
Settlements reclassified to interest expense, net	1.3	-	1.3	1.6	-	1.6
Other comprehensive income (loss) attributable to noncontrolling interests	$14.4	$ -	14.4	$55.7	$ (0.3)	55.4
Comprehensive income attributable to noncontrolling interests			$21.9			$90.3
Total comprehensive income			$38.5			$104.9

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (CONTINUED)

	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 attributable to Targa Resources Corp.			$28.3			$18.2
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$1.9	$ (0.7)	1.2	$15.3	$ (6.1)	9.2
Settlements reclassified to revenues	(1.7)	0.7	(1.0)	(3.5)	1.4	(2.1)
Interest rate swaps:						
Settlements reclassified to interest expense, net	0.5	(0.2)	0.3	0.5	(0.3)	0.2
Other comprehensive income (loss) attributable to Targa Resources Corp.	$0.7	$ (0.2)	0.5	$12.3	$ (5.0)	7.3
Comprehensive income attributable to Targa Resources Corp.			$28.8			$25.5
Net income attributable to noncontrolling interests			$27.9			$94.4
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	$11.8	$ -	11.8	$77.7	$ (0.5)	77.2
Settlements reclassified to revenues	(10.8)	-	(10.8)	(12.2)	0.1	(12.1)
Interest rate swaps:						
Settlements reclassified to interest expense, net	2.8	-	2.8	3.6	-	3.6
Other comprehensive income (loss) attributable to noncontrolling interests	$3.8	$ -	3.8	$69.1	$ (0.4)	68.7
Comprehensive income attributable to noncontrolling interests			$31.7			$163.1
Total comprehensive income			$60.5			$188.6

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Common Stock		Additional Paid in	Accumulated	Accumulated Other Comprehensive Income	Treasury Shares		Noncontrolling	
	Shares	Amount	Capital	Deficit	(Loss)	Shares	Amount	Interests	Total
	(Unaudited)								
	(In millions, except shares in thousands)								
Balance, December 31, 2012	42,295	$ -	$ 184.4	$ (32.0)	$ 1.2	198	$ (9.5)	$ 1,609.3	$ 1,753.4
Compensation on equity grants	36	-	3.8	-	-	-	-	3.0	6.8
Accrual of distribution equivalent rights	-	-	-	-	-	-	-	(0.7)	(0.7)
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	260.3	260.3
Receivables from unit offerings	-	-	(32.8)	-	-	-	-	-	(32.8)
Impact of Partnership equity transactions	-	-	16.5	-	-	-	-	(16.5)	-
Dividends	-	-	(40.3)	-	-	-	-	-	(40.3)
Distributions to owners	-	-	-	-	-	-	-	(125.9)	(125.9)
Other comprehensive income (loss)	-	-	-	-	0.5	-	-	3.8	4.3
Net income	-	-	-	28.3	-	-	-	27.9	56.2
Balance, June 30, 2013	42,331	$ -	$ 131.6	$ (3.7)	$ 1.7	198	$ (9.5)	$ 1,761.2	$ 1,881.3
Balance, December 31, 2011	42,398	$ -	$ 229.5	$ (70.1)	$ (1.3)	-	$ -	$ 1,172.6	$ 1,330.7
Compensation on equity grants	42	-	7.1	-	-	-	-	1.7	8.8
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	115.2	115.2
Impact of Partnership equity transactions	-	-	(18.8)	-	-	-	-	18.8	-
Dividends	-	-	(29.8)	-	-	-	-	(0.1)	(29.9)
Distributions to owners	-	-	(1.2)	-	-	-	-	(103.9)	(105.1)
Other comprehensive income (loss)	-	-	-	-	7.3	-	-	68.7	76.0
Net income	-	-	-	18.2	-	-	-	94.4	112.6
Balance, June 30, 2012	42,440	$ -	$ 186.8	$ (51.9)	$ 6.0	-	$ -	$ 1,367.4	$ 1,508.3

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2013	2012
	(Unaudited)	
Cash flows from operating activities	(In millions)	
Net income	$56.2	$112.6
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	8.1	9.5
Compensation on equity grants	6.8	8.8
Depreciation and amortization expense	129.7	95.7
Accretion of asset retirement obligations	2.0	2.0
Deferred income tax expense	0.7	2.7
Equity earnings, net of distributions	(4.5)	-
Risk management activities	-	1.1
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	77.6	204.0
Inventory	(49.7)	(0.3)
Accounts payable and other liabilities	(75.4)	(232.0)
Net cash provided by operating activities	162.7	204.0
Cash flows from investing activities		
Outlays for property, plant and equipment	(444.5)	(238.7)
Investment in unconsolidated affiliate	-	(13.7)
Return of capital from unconsolidated affiliate	-	0.4
Other, net	(10.5)	0.9
Net cash used in investing activities	(455.0)	(251.1)
Cash flows from financing activities		
Partnership loan facilities:		
Proceeds	1,305.0	725.0
Repayments	(1,181.4)	(683.0)
Partnership accounts receivable securitization facility:		
Proceeds	207.7	-
Repayments	(82.4)	-
Non-Partnership loan facilities:		
Proceeds	30.0	-
Repayments	(34.0)	-
Costs incurred in connection with financing arrangements	(11.7)	(4.5)
Distributions to owners	(125.9)	(105.1)
Proceeds from sale of common units of the Partnership	231.2	115.2
Dividends to common shareholders	(39.6)	(28.8)
Net cash provided by financing activities	298.9	18.8
Net change in cash and cash equivalents	6.6	(28.3)
Cash and cash equivalents, beginning of period	76.3	145.8
Cash and cash equivalents, end of period	$82.9	$117.5

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
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

Targa Resources Corp. ("TRC") is a Delaware corporation formed in October 2005. Our common stock is listed on the NYSE under the symbol "TRGP." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Targa" are intended to mean our consolidated business and operations, including our wholly owned subsidiary TRI Resources Inc. ("TRI").

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.

One of our indirect subsidiaries is the sole general partner of Targa Resources Partners LP (the "Partnership"). Because we control the general partner of the Partnership, under GAAP, we must reflect our ownership interests in the Partnership on a consolidated basis. Accordingly, the Partnership's financial results are included in our consolidated financial statements even though the distribution or transfer of Partnership assets is limited by the terms of the Partnership's partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by us are reflected in our results of operations as net income attributable to noncontrolling interests and in our balance sheet equity section as noncontrolling interests in subsidiaries. Throughout these footnotes, we make a distinction where relevant between financial results of the Partnership versus those of a standalone parent and its non-partnership subsidiaries.

As of June 30, 2013, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;

- all Incentive Distribution Rights (“IDRs”); and

- 12,945,659 common units of the Partnership, representing a 12.2% limited partnership interest.

The Partnership is 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. See Note 16 for an analysis of our and the Partnership’s operations by segment.

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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 the Partnership has 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 the Partnership's 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 12 in accordance with these new standards updates.

Note 4 –Business Acquisitions

On December 31, 2012, the Partnership 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, the Partnership 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.

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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 share amounts)			
Revenues	$5,885.7	$5,909.9	$1,324.0	$2,972.7
Net income	159.3	129.5	34.5	93.6
Less: Net income attributable to noncontrolling interests	121.2	83.5	23.5	70.9
Net income attributable to Targa Resources Corp.	$38.1	$46.0	$11.0	$22.7
Net income per common share - Basic	$0.93	$1.12	$0.27	$0.55
Net income per common share - Diluted	$0.91	$1.10	$0.26	$0.54

The Partnership applied the same assumptions used in preparing the year-end pro forma schedules reported in its Annual Report on Form 10-K except for the following adjustments to conform to its 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

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Note 6 — Property, Plant and Equipment and Intangible Assets

	June 30, 2013			December 31, 2012			
	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Estimated Useful Lives (In Years)
Gathering systems	$2,075.7	$ -	$ 2,075.7	$1,975.3	$ -	$ 1,975.3	5 to 20
Processing and fractionation facilities	1,269.4	6.6	1,276.0	1,251.6	6.6	1,258.2	5 to 25
Terminaling and storage facilities	526.0	-	526.0	462.0	-	462.0	5 to 25
Transportation assets	292.6	-	292.6	292.5	-	292.5	10 to 25
Other property, plant and equipment	88.7	0.3	89.0	84.6	0.2	84.8	3 to 25
Land	87.4	-	87.4	87.1	-	87.1	-
Construction in progress	820.1	-	820.1	548.1	-	548.1	-
Property, plant and equipment	$5,159.9	$ 6.9	$ 5,166.8	$4,701.2	$ 6.8	$ 4,708.0	
Accumulated depreciation	(1,281.3)	(2.1)	(1,283.4)	(1,168.0)	(2.0)	(1,170.0)	
Property, plant and equipment, net	$3,878.6	$ 4.8	$ 3,883.4	$3,533.2	$ 4.8	$ 3,538.0	
Intangible assets	$681.8	$ -	$ 681.8	$681.9	$ -	$ 681.9	20
Accumulated amortization	(14.7)	-	(14.7)	(1.1)	-	(1.1)	
Intangible assets, net	$667.1	$ -	$ 667.1	$680.8	$ -	$ 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	142.6	154.4

Interest	39.9	39.5
Compensation and benefits	43.0	40.7
Other	6.0	27.6
	$597.4	$ 679.0

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Note 8 — Debt Obligations

	June 30, 2013	December 31, 2012
Long-term debt:		
Non-Partnership obligations:		
TRC Senior secured revolving credit facility, variable rate, due October 2017 (1)	$78.0	$ 82.0
Obligations of the Partnership: (2)		
Senior secured revolving credit facility, variable rate, due October 2017 (3)	225.0	620.0
Senior unsecured notes, 11¼% fixed rate, due July 2017 (4)	72.7	72.7
Unamortized discount	(2.3)	(2.5)
Senior unsecured notes, 7 % fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6 % fixed rate, due February 2021	483.6	483.6
Unamortized discount	(29.3)	(30.5)
Senior unsecured notes, 6 % 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 (5)	125.3	-
Total long-term debt	$2,728.0	$ 2,475.3
Irrevocable standby letters of credit:		
Letters of credit outstanding under TRC Senior secured credit facility (1)	$-	$ -
Letters of credit outstanding under the Partnership senior secured revolving credit facility (3)	47.9	45.3
	$47.9	$ 45.3

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(1) As of June 30, 2013, availability under TRC's $150 million senior secured revolving credit facility was $72.0 million.

(2) While we consolidate the debt of the Partnership in our financial statements, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.

(3) As of June 30, 2013, availability under the Partnership's $1.2 billion senior secured revolving credit facility was $927.1 million.

(4) 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 the Partnership's long-term Senior Secured Credit Facility (the "TRP Revolver"). See "Subsequent Events" below.

(5) All amounts outstanding under the Partnership's Securitization Facility are reflected as long-term debt in our balance sheet because the Partnership has the ability and intent to fund the Securitization Facility's borrowing with availability under the Partnership's Revolver ("the TRP Revolver").

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

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC senior secured revolving credit facility	2.9% - 3.0%	3.0%
Partnership's senior secured revolving credit facility	1.9% - 4.5%	2.3%
Partnership's accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

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

The Partnership's Accounts Receivable Securitization Facility

In January 2013, the Partnership 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 the Partnership's consolidated subsidiaries (Targa Liquids Marketing and Trade LLC or "TLMT") sells or contributes receivables, without recourse, to another of the Partnership's 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.

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April 2013 Shelf

In April 2013, the Partnership filed with the SEC a universal shelf registration statement (the “April 2013 Shelf”), which provides the Partnership with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and the Partnership’s 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.

The Partnership’s 4¼% Senior Notes due 2023 (“4¼% Notes”)

In May 2013, the Partnership 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 the Partnership’s 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 the Partnership’s future subordinated indebtedness and are unconditionally guaranteed by certain of the Partnership’s subsidiaries. The 4¼% Notes are effectively subordinated to all secured indebtedness under the Partnership’s credit agreement, which is secured by substantially all of the Partnership’s 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.

The Partnership 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. The Partnership 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 the Partnership) 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.

The Partnership 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, the Partnership paid $106.4 million plus accrued interest to redeem $100 million of the outstanding 6 % Senior Notes due 2022 (the “6 % 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, the Partnership 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.

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On July 29, 2013, the Partnership 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, the Partnership filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows the Partnership 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, the Partnership entered into an Equity Distribution Agreement (“2012 EDA”) with Citigroup Global Markets Inc. (“Citigroup”) pursuant to which the Partnership may sell, at its option, up to an aggregate of $100 million of its 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, the Partnership issued 2,420,046 common units under the 2012 EDA, receiving net proceeds of $94.8 million. We contributed $2.0 million to maintain our 2% general partner interest.

In March 2013, the Partnership 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 sales agents, pursuant to which the Partnership may sell, at its option, up to an aggregate of $200 million of the Partnership common units. During the six months ended June 30, 2013, the Partnership 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, we contributed $5.4 million to maintain our 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, the Partnership must distribute all of its 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 the Partnership during the six months ended June 30, 2013.

Three Months Ended	Date Paid or to be Paid	Distributions Limited Partners Common	Distributions General Partner Incentive	Distributions General Partner 2%	Total	Distributions to Targa Resources Corp.	Distributions per limited partner unit
(In millions, except per unit amounts)							
June 30, 2013	August 14, 2013	$75.8	$24.6	$2.0	$102.4	$ 35.9	$ 0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	33.0	0.6975
December 31, 2012	February 14, 2013	69.0	20.1	1.8	90.9	30.7	0.6800

Note 10 — Common Stock and Related Matters

The following table details the dividends declared and/or paid by us during the six months ended June 30, 2013:

Three Months Ended	Date Paid or to be Paid	Total Dividend Declared	Amount of Dividend Paid	Accrued Dividends (1)	Dividend Declared per Share of Common

					Stock
(In millions, except per share amounts)					
June 30, 2013	August 15, 2013	$ 22.5	$ 22.1	$ 0.4	$ 0.53250
March 31, 2013	May 16, 2013	21.0	20.6	0.4	0.49500
December 31, 2012	February 15, 2013	19.4	19.0	0.4	0.45750

(1) Represents accrued dividends on the restricted shares that are payable upon vesting.

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Note 11 — Earnings per Common Share

The following table sets forth a reconciliation of net income and weighted average shares outstanding used in computing basic and diluted net income per common share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	$22.5	$43.5	$56.2	$112.6
Less: Net income attributable to noncontrolling interests	7.5	34.9	27.9	94.4
Net income attributable to common shareholders	$15.0	$8.6	$28.3	$18.2
Weighted average shares outstanding - basic	41.6	41.0	41.6	41.0
Net income available per common share - basic	$0.36	$0.21	$0.68	$0.44
Weighted average shares outstanding	41.6	41.0	41.6	41.0
Dilutive effect of unvested stock awards	0.5	0.9	0.4	0.8
Weighted average shares outstanding - diluted	42.1	41.9	42.0	41.8
Net income available per common share - diluted	$0.36	$0.21	$0.67	$0.44

Note 12 — Derivative Instruments and Hedging Activities

Partnership Commodity Hedges

The primary purpose of the Partnership’s commodity risk management activities is to manage its exposure to commodity price risk and reduce volatility in its operating cash flow due to fluctuations in commodity prices. The Partnership has hedged the commodity prices associated with a portion of its 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. The Partnership has 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 the Partnership’s 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 the Partnership’s 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. The Partnership’s natural gas and NGL hedges are settled using published index prices for delivery at various locations, which closely approximate the Partnership’s actual natural gas and NGL delivery points.

The Partnership hedges a portion of its 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 the Partnership to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of its underlying condensate equity volumes.

At June 30, 2013, the notional volumes of the Partnership's 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	-	-

The Partnership also enters into derivative instruments to help manage other short-term commodity-related business risks. The Partnership has not designated these derivatives as hedges, and records changes in fair value and cash settlements to revenues.

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The Partnership's 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:

	Balance Sheet Location	Fair Value as of June 30, 2013 Derivative Assets	Fair Value as of June 30, 2013 Derivative Liabilities	Fair Value as of December 31, 2012 Derivative Assets	Fair Value as of December 31, 2012 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:

June 30, 2013	Gross Presentation Asset Position	Gross Presentation Liability Position	Pro forma Net Presentation Asset Position	Pro forma Net Presentation 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 the Partnership’s 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.

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The estimated fair value of the Partnership's 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.

The Partnership's payment obligations in connection with substantially all of these hedging transactions are secured by a first priority lien in the collateral securing its senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its 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:

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Derivatives in Cash Flow Hedging Relationships	2013	2012	2013	2012
Commodity contracts	$21.2	$77.7	$13.7	$93.0
	$21.2	$77.7	$13.7	$93.0

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2013	2012	2013	2012
Interest expense, net	$(1.6)	$(1.9)	$(3.3)	$(4.1)
Revenues	5.9	13.8	12.5	15.7
	$4.3	$11.9	$9.2	$11.6

Hedge ineffectiveness was immaterial for all periods presented.

Our consolidated earnings are also affected by the Partnership's 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, before tax	$ 3.2	$ 3.2
Commodity hedges, after tax	2.0	1.9
Interest rate hedges, before tax	(0.7)	(1.2)
Interest rate hedges, after tax	(0.4)	(0.7)

As of June 30, 2013, net gains of $20.5 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 13 for additional disclosures related to derivative instruments and hedging activities.

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Note 13 — 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

The Partnership’s derivative instruments consist of financially settled commodity swap and option contracts and fixed price commodity contracts with certain counterparties. The Partnership determines the fair value of its 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. The Partnership has consistently applied these valuation techniques in all periods presented and we believe the Partnership has obtained the most accurate information available for the types of derivative contracts the Partnership holds.

The fair values of the Partnership’s 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 the Partnership expects to receive in the future on its 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 the Partnership’s 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:

- senior secured revolving credit facilities and the Partnership’s 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.

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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				
	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	$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	82.9	82.9	-	-	-
TRC Senior secured revolving credit facility	78.0	78.0	-	78.0	-
Partnership's Senior secured revolving credit facility	225.0	225.0	-	225.0	-
Partnership's Senior unsecured notes	2,299.7	2,317.5	-	2,317.5	-
Partnership's 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	76.3	76.3	-	-	-
TRC Senior secured revolving credit facility	82.0	82.0	-	82.0	-
Partnership's Senior secured revolving credit facility	620.0	620.0	-	620.0	-
Partnership's 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 the Partnership’s 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, the Partnership had several natural gas basis swaps categorized as Level 3. The significant unobservable inputs used in the fair value measurements of the Partnership's 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.

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In 2012, the Partnership 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 14 — 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 15 - Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2013	2012
Cash:		
Interest paid, net of capitalized interest	$55.9	$45.6
Income taxes paid, net of refunds	23.1	18.2
Non-cash:		
Deadstock inventory transferred to property, plant and equipment	22.2	2.8
Accrued dividends on unvested equity awards	0.7	1.0
Receivables from unit offerings	32.8	-

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Note 16 — Segment Information

The Partnership reports its 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 its hedging activities are reported in Other.

The Partnership’s 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.

The Partnership’s Logistics and Marketing division is also referred to as its Downstream Business. The Partnership’s 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 the Partnership’s other operations, as well as transporting natural gas and NGLs.

The Partnership’s 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 the Partnership’s Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana.

The Partnership’s 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 the Partnership’s 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 the Partnership from its 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 the Partnership’s commodity hedging activities included in operating margin. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column.

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Segment information is shown in the following tables. We have segregated the following segment information between Partnership and non-Partnership activities. Partnership activities have been presented on a common control accounting basis, which reflects the drop-down transactions between us and the Partnership as if they occurred in prior periods similar to a pooling of interests. The non-Partnership results include activities related to certain assets and liabilities contractually excluded from the drop-down transactions and certain historical hedge activities that could not be reflected under GAAP in the Partnership common control results.

	Three Months Ended June 30, 2013							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
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	$ 84.5	$ 5,407.1
Capital expenditures	$115.1	$ 4.3	$114.1	$ 0.8	$-	$ 1.4	$ -	$ 235.7

	Three Months Ended June 30, 2012							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$46.6	$ 51.7	$54.5	$ 1,068.5	$12.8	$ -	$ 0.7	$ 1,234.8
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	-	0.7	1,319.1
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)	$ 0.7	$ 1,319.1
Operating margin	$53.9	$ 28.0	$45.7	$ 26.2	$12.8	$ -	$ 0.6	$ 167.2
Other financial information:								

Total assets	$1,677.2	$ 423.8	$ 925.8	$ 448.8	$77.6	$ 113.2	$ 114.1	$ 3,780.5
Capital expenditures	$46.6	$ 2.6	$ 89.9	$ 0.4	$ -	$ 0.9	$ -	$ 140.4

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	Six Months Ended June 30, 2013							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$89.2	$ 152.6	$78.2	$ 2,278.9	$12.3	$ -	$ (0.1)	$ 2,611.1
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	-	(0.1)	2,839.4
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)	$ (0.1)	$ 2,839.4
Operating margin	$121.1	$ 40.1	$108.6	$ 61.4	$12.3	$ -	$ (0.2)	$ 343.3
Other financial information:								
Total assets	$2,950.9	$ 403.9	$1,303.6	$ 509.6	$28.8	$ 125.8	$ 84.5	$ 5,407.1
Capital expenditures	$211.2	$ 10.8	$217.8	$ 0.7	$-	$ 2.1	$ -	$ 442.6

	Six Months Ended June 30, 2012							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$92.0	$ 111.5	$ 100.0	$ 2,485.8	$14.1	$ -	$ 1.0	$ 2,804.4
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	-	1.0	2,964.9
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)	$ 1.0	$ 2,964.9
Operating margin	$126.9	$ 74.3	$ 88.7	$ 52.4	$14.1	$ -	$ 0.8	$ 357.2
Other financial information:								
Total assets	$1,677.2	$ 423.8	$ 925.8	$ 448.8	$77.6	$ 113.2	$ 114.1	$ 3,780.5
Capital expenditures	$72.8	$ 4.6	$ 150.0	$ 9.5	$-	$ 1.5	$ 0.3	$ 238.7

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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	12.8	12.4	15.0
	1,327.5	1,234.8	2,611.1	2,804.4
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	$1,319.1	$2,839.4	$2,964.9

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
Operating margin	$169.1	$167.2	$343.3	$357.2
Depreciation and amortization expense	(65.7)	(48.3)	(129.7)	(95.7)
General and administrative expense	(38.4)	(35.7)	(74.6)	(70.8)
Interest expense, net	(32.4)	(30.5)	(64.5)	(61.0)
Income tax expense	(8.0)	(8.6)	(17.5)	(18.8)
Other, net	(2.1)	(0.6)	(0.8)	1.7
Net income	$22.5	$43.5	$56.2	$112.6

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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

Financial Presentation

Targa Resources Corp. is a publicly traded Delaware corporation formed in October 2005. Our common stock is listed on the NYSE under the symbol "TRGP." In this Quarterly Report, unless the context requires otherwise, references to "we," "us," "our," the "Company," or "Targa" are intended to mean our consolidated business and operations, including our wholly owned subsidiary TRI Resources Inc. ("TRI").

We own general and limited partner interests, including Incentive Distribution Rights ("IDRs"), in Targa Resources Partners LP (the "Partnership"); a publicly traded Delaware limited partnership that is a leading provider of midstream natural gas and natural gas liquid services in the United States. Common units of the Partnership are listed on the NYSE under the symbol "NGLS."

Our primary business objective is to increase our cash available for dividends to our stockholders by assisting the Partnership in executing its business strategy. We may facilitate the Partnership's growth through various forms of financial support, including, but not limited to, modifying the Partnership's IDRs, exercising the Partnership's IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership, if needed, to support its ability to make distributions. We also may enter into other economic transactions intended to increase our ability to make cash available for dividends over time. In addition, we may acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

An indirect subsidiary of ours is the general partner of the Partnership. Because we control the general partner, under GAAP we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, the Partnership's financial results are included in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by us are reflected in our results of operations as net income attributable to noncontrolling interests. Therefore, throughout this discussion, we make a distinction where relevant between financial results of the Partnership versus those of us as a standalone parent including our non-Partnership subsidiaries.

The Partnership files its own separate Quarterly Report. The results of operations included in our consolidated financial statements will differ from the results of operations of the Partnership primarily due to the financial effects of:

- noncontrolling interests in the Partnership;

- our separate debt obligations;

- certain general and administrative costs applicable to us as a separate public company;

- certain non-operating assets and liabilities that we retained; and

· federal income taxes.

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Our Operations

Currently, we have no separate, direct operating activities apart from those conducted by the Partnership. As such, our cash inflows will primarily consist of cash distributions from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions.

The Partnership’s Operations

The Partnership is a leading provider of midstream natural gas, NGLs, terminaling and crude oil gathering services in the United States. It is 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.

The Partnership reports its 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 its hedging activities are reported in Other.

The Partnership’s 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.

The Partnership’s Logistics and Marketing division is also referred to as its Downstream Business. The Partnership’s 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 the Partnership’s other operations, as well as transporting natural gas and NGLs.

The Partnership’s 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 the Partnership’s Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana.

The Partnership’s 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 the Partnership’s 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 the Partnership from its 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 the Partnership’s commodity hedging activities included in operating margin.

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2013 Developments

Badlands Acquisition

On January 1, 2013, the Partnership assumed operational control of the Badlands assets and commenced integration activities. These assets are still in a start-up phase. The Partnership anticipates 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, the Partnership 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 the Partnership's earnings and reported as Other income (expense) in the Consolidated Statement of Operations. At June 30, 2013, the Partnership 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, the Partnership 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 the Partnership's consolidated subsidiaries (TLMT) sells or contributes receivables, without recourse, to another of the Partnership's 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 its 2012 and 2013 EDAs, the Partnership 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. We contributed $4.0 million to the Partnership to maintain our 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 the Partnership's capital needs, the Partnership at its option, can sell additional common units up to an aggregate amount of $35.6 million under these agreements.

In April 2013, the Partnership filed with the SEC a universal shelf registration statement (the April 2013 Shelf), which provides the Partnership with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and the Partnership's 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, the Partnership privately placed $625.0 million in aggregate principal amount of the 4¼% Notes. The 4¼% Notes resulted in approximately $618.1 million of net proceeds, which were used to reduce borrowings under the Partnership's senior secured revolving credit facility and for general partnership purposes.

In June 2013, the Partnership redeemed $100 million of the outstanding 6 % 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.

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In July 2013, the Partnership 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, the Partnership 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 12 in accordance with these new standards updates.

How We Evaluate Our Operations

Our consolidated operations include the operations of the Partnership due to our ownership and control of the general partner. We currently have no separate, direct operating activities from those conducted by the Partnership. Our financial results differ from the Partnership's due to the financial effects of: noncontrolling interests in the Partnership, our separate debt obligations, certain non-operating costs associated with assets and liabilities that we retained and were not included in asset conveyances to the Partnership, and certain general and administrative costs applicable to us as a separate public company. Management's primary measure of analyzing our performance is the non-GAAP measure distributable cash flow.

Distributable Cash Flow

We define distributable cash flow as distributions due to us from the Partnership, less our specific general and administrative costs as a separate public reporting entity, the interest carry costs associated with our debt and taxes attributable to our earnings. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts, and others to compare basic cash flows generated by us to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash dividends. Distributable cash flow is also an important financial measure for our shareholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether we are generating cash flow at a level that can sustain or support an increase in our quarterly dividend rates. Distributable cash flow is also a quantitative standard used throughout the investment community because the share value is generally determined by the share's yield (which in turn is based on the amount of cash dividends the entity pays to a shareholder).

The economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to pay dividends to our investors.

The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. 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.

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Our Non-GAAP Measures

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 process.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Targa Resources Corp. distributable Cash Flow				
Distributions declared by Targa Resources Partners LP associated with:				
General Partner Interests	$2.0	$1.5	$3.9	$2.9
Incentive Distribution Rights	24.6	14.4	46.7	27.1
Common Units	9.3	8.3	18.3	16.4
Total distributions declared by Targa Resources Partners LP	35.9	24.2	68.9	46.4
Income (expenses) of TRC Non-Partnership				
General and administrative expenses	(2.3)	(2.2)	(4.3)	(4.4)
Interest expense, net	(0.8)	(1.1)	(1.5)	(2.2)
Current cash tax expense (1)	(5.9)	(5.8)	(13.4)	(12.7)
Taxes funded with cash on hand (2)	2.5	2.2	5.0	4.4
Other income (expense)	0.1	-	-	-
Targa Resources Corp. distributable cash flow	$29.5	$17.3	$54.7	$31.5

(1) Excludes $1.2 million and $2.4 million of non-cash current tax expense arising from amortization of deferred long-term tax assets from drop-down gains realized for tax purposes and paid in 2010 for the three and six months ended June 30, 2013 and 2012.

(2) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop-down transactions that were treated as sales for income tax purposes.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Reconciliation of net income attributable to Targa Resources Corp. to distributable Cash Flow				
Net income of Targa Resources Corp.	$22.5	$43.5	$56.2	$112.6
Less: Net income of Targa Resources Partners LP	(32.7)	(54.7)	(78.0)	(136.6)
Net loss for TRC Non-Partnership	(10.2)	(11.2)	(21.8)	(24.0)
TRC Non-Partnership income tax expense	7.1	7.8	15.8	17.0
Distributions from the Partnership	35.9	24.2	68.9	46.4
Non-cash loss (gain) on hedges	0.1	(0.6)	0.1	(1.0)
Depreciation - Non-Partnership	-	0.7	0.1	1.4
Current cash tax expense (1)	(5.9)	(5.8)	(13.4)	(12.7)
Taxes funded with cash on hand (2)	2.5	2.2	5.0	4.4
Targa Resources Corp. distributable cash flow	$29.5	$17.3	$54.7	$31.5

(1) Excludes $1.2 million and $2.4 million of non-cash current tax expense arising from amortization of deferred long-term tax assets from drop-down gains realized for tax purposes and paid in 2010 for the three and six months ended June 30, 2013 and 2012.

(2) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop-down transactions that were treated as sales for income tax purposes.

How We Evaluate the Partnership's Operations

The Partnership's profitability is a function of the difference between: (i) the revenues the Partnership receives from its operations, including fee-based revenues from services and revenues from the crude oil, natural gas, NGLs and condensate the Partnership sells, and (ii) the costs associated with conducting the Partnership's operations, including the costs of crude oil, wellhead natural gas and mixed NGLs that the Partnership purchases as well as operating and general and administrative costs and the impact of commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in the Partnership's revenues alone are not necessarily indicative of increases or decreases in its profitability. The Partnership's 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 its systems are important factors in determining its profitability. The Partnership's profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for its products and services, utilization of its assets and changes in its customer mix.

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The Partnership's profitability is also impacted by fee-based revenues. The Partnership's 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 the Partnership's 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

The Partnership's profitability is impacted by its 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 its 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, the Partnership's profitability is impacted by its ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to its Downstream Business' fractionation facilities. The Partnership fractionates NGLs generated by its gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities. The Partnership's recently acquired assets in the Bakken Shale should allow it 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 the Partnership's system, which should provide further opportunities to enhance medium and long-term growth in the Bakken Shale.

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

As part of monitoring the efficiency of its operations, the Partnership measures the difference between the volume of natural gas received at the wellhead or central delivery points on its gathering systems and the volume received at the inlet of its processing plants as an indicator of fuel consumption and line loss. The Partnership also tracks 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 its crude oil gathering and logistics assets. These volume, recovery and fuel consumption measurements are an important part of the Partnership's 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 the Partnership's operating expenses. These expenses, other than fuel and power, generally remain relatively stable and independent of the volumes through its systems but fluctuate depending on the scope of the activities performed during a specific period.

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Capital Expenditures

Capital projects associated with growth and maintenance projects are closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the ensuing operational performance versus capital investment economic analysis is evaluated. The Partnership has seen a substantial increase in its total capital spent over the last three years and currently has significant internal growth projects that it closely monitors.

Gross Margin

The Partnership defines gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as the Partnership's contract mix and hedging program. The Partnership defines 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

The Partnership defines operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of the Partnership's 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 the Partnership's 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 the Partnership's assets without regard to financing methods, capital structure or historical cost basis;

- the Partnership's 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 the Partnership's 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, the Partnership's 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

The Partnership defines 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 the Partnership and by external users of our financial statements such as investors, commercial banks and others.

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

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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 the Partnership's 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 the Partnership's industry, the Partnership's 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

The Partnership defines 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 the Partnership and by external users of the Partnership's financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by the Partnership (prior to the establishment of any retained cash reserves by the board of directors of its general partner) to the cash distributions the Partnership expects to pay the Partnership's unitholders. Using this metric, the Partnership's management and external users of its 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 the Partnership's unitholders since it serves as an indicator of the Partnership's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether the Partnership is generating cash flow at a level that can sustain or support an increase in the Partnership's 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 the Partnership's 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 the Partnership's 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 of the Partnership

The following tables reconcile the non-GAAP financial measures of the Partnership 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.

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	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,		Six Months Ended June 30,	
	2013	2012	2013	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 us, the noncontrolling interest portion of maintenance capital expenditures, depreciation and amortization expenses.

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Financial Information – Partnership versus Non-Partnership

As a supplement to the financial statements included in this Quarterly Report, we present the following tables, which segregate our consolidated balance sheet, results of operations and statement of cash flows between Partnership and Non-Partnership activities. Partnership results are presented on a common control accounting basis – the same basis reported in the Partnership's Quarterly Report on Form 10-Q. Except when otherwise noted, the remainder of this management's discussion and analysis refers to these disaggregated results.

Balance Sheets – Partnership versus Non-Partnership

	June 30, 2013			December 31, 2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
ASSETS						
Current assets:						
Cash and cash equivalents (1)	$82.9	$72.7	$ 10.2	$76.3	$68.0	$ 8.3
Trade receivables, net	435.8	435.9	(0.1)	514.9	514.9	-
Inventory	138.3	138.3	-	99.4	99.4	-
Assets from risk management activities	23.2	23.2	-	29.3	29.3	-
Other current assets (1)	17.7	1.8	15.9	13.4	3.3	10.1
Total current assets	697.9	671.9	26.0	733.3	714.9	18.4
Property, plant and equipment, at cost (1)	5,166.8	5,159.9	6.9	4,708.0	4,701.2	6.8
Accumulated depreciation	(1,283.4)	(1,281.3)	(2.1)	(1,170.0)	(1,168.0)	(2.0)
Property, plant and equipment, net	3,883.4	3,878.6	4.8	3,538.0	3,533.2	4.8
Other intangible assets, net	667.1	667.1	-	680.8	680.8	-
Long-term assets from risk management activities	5.6	5.6	-	5.1	5.1	-
Other long-term assets (2)	153.1	99.4	53.7	147.8	91.7	56.1
Total assets	$5,407.1	$5,322.6	$ 84.5	$5,105.0	$5,025.7	$ 79.3
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (3)	$597.4	$567.1	$ 30.3	$679.0	$639.8	$ 39.2
Affiliate payable (receivable) (4)	-	49.8	(49.8)	-	61.4	(61.4)
Deferred income taxes (5)	7.4	-	7.4	0.2	-	0.2
Liabilities from risk management activities	3.8	3.8	-	7.4	7.4	-
Total current liabilities	608.6	620.7	(12.1)	686.6	708.6	(22.0)
Long-term debt	2,728.0	2,650.0	78.0	2,475.3	2,393.3	82.0
Long-term liabilities from risk management activities	1.8	1.8	-	4.8	4.8	-
Deferred income taxes (5)	125.0	12.0	113.0	131.2	11.2	120.0
Other long-term liabilities (6)	62.4	51.4	11.0	53.7	47.7	6.0

Total liabilities	3,525.8	3,335.9	189.9	3,351.6	3,165.6	186.0
Total owners' equity	1,881.3	1,986.7	(105.4)	1,753.4	1,860.1	(106.7)
Total liabilities and owners' equity	$5,407.1	$5,322.6	$ 84.5	$5,105.0	$5,025.7	$ 79.3

The major Non-Partnership balance sheet items relate to:

(1) Corporate assets consisting of cash, administrative property and equipment, and prepaid insurance, as applicable.

(2) Long-term tax assets primarily related to gains on 2010 drop-down transactions recognized as sales of assets for tax purposes.

(3) Accrued current employee liabilities related to payroll and incentive compensation plans and taxes payable.

(4) Intercompany receivable with the Partnership related to the ongoing execution of the Omnibus Agreement.

(5) Current and long-term deferred income tax balances.

(6) Long-term liabilities related to incentive compensation plans and deferred rent related to the headquarters office lease.

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Results of Operations – Partnership versus Non-Partnership

	Three Months Ended June 30, 2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Revenues (1)	$1,441.6	$1,441.6	$ -	$1,319.1	$1,318.4	$ 0.7
Costs and Expenses:						
Product purchases	1,176.4	1,176.4	-	1,074.6	1,074.6	-
Operating expenses	96.1	96.1	-	77.3	77.2	0.1
Depreciation and amortization (2)	65.7	65.7	-	48.3	47.6	0.7
General and administrative (3)	38.4	36.1	2.3	35.7	33.5	2.2
Other operating (income) expense	4.1	4.1	-	-	-	-
Income from operations	60.9	63.2	(2.3)	83.2	85.5	(2.3)
Other income (expense):						
Interest expense, net - third party (4)	(32.4)	(31.6)	(0.8)	(30.5)	(29.4)	(1.1)
Equity earnings	2.9	2.9	-	(0.2)	(0.2)	-
Loss on debt redemption	(7.4)	(7.4)	-	-	-	-
Other income (expense)	6.5	6.5	-	(0.4)	(0.4)	-
Income (loss) before income taxes	30.5	33.6	(3.1)	52.1	55.5	(3.4)
Income tax expense	(8.0)	(0.9)	(7.1)	(8.6)	(0.8)	(7.8)
Net income (loss)	$22.5	$32.7	$ (10.2)	$43.5	$54.7	$ (11.2)
Less: Net income attributable to noncontrolling interests (5)	7.5	6.4	1.1	34.9	7.9	27.0
Net income (loss) after noncontrolling interests	$15.0	$26.3	$ (11.3)	$8.6	$46.8	$ (38.2)

The major Non-Partnership results of operations relate to:

(1) Amortization of AOCI related to Versado hedges dropped down to the Partnership, and OCI related to terminated hedges.
(2) Depreciation on assets excluded from drop-down transactions and corporate administrative assets.
(3) General and administrative expenses retained by TRC related to its status as a public entity.
(4) Interest expense related to TRC debt obligations.
(5) TRC noncontrolling interest in the Partnership.

	Six Months Ended June 30, 2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Revenues (1)	$2,839.4	$2,839.5	$ (0.1)	$2,964.9	$2,963.9	$ 1.0
Costs and Expenses:						
Product purchases	2,313.9	2,313.9	-	2,458.8	2,458.7	0.1
Operating expenses	182.2	182.1	0.1	148.9	148.8	0.1

Depreciation and amortization (2)	129.7	129.6	0.1	95.7	94.3	1.4
General and administrative (3)	74.6	70.3	4.3	70.8	66.4	4.4
Other operating (income) expense	4.2	4.2	-	(0.1)	(0.1)	-
Income from operations	134.8	139.4	(4.6)	190.8	195.8	(5.0)
Other income (expense):						
Interest expense, net - third party (4)	(64.5)	(63.0)	(1.5)	(61.0)	(58.8)	(2.2)
Equity earnings	4.5	4.5	-	1.9	1.9	-
Loss on debt redemption	(7.4)	(7.4)	-	-	-	-
Other income (expense)	6.3	6.3	-	(0.3)	(0.5)	0.2
Income (loss) before income taxes	73.7	79.8	(6.1)	131.4	138.4	(7.0)
Income tax expense	(17.5)	(1.8)	(15.7)	(18.8)	(1.8)	(17.0)
Net income (loss)	$56.2	$78.0	$ (21.8)	$112.6	$136.6	$ (24.0)
Less: Net income attributable to noncontrolling interests (5)	27.9	12.8	15.1	94.4	19.6	74.8
Net income (loss) after noncontrolling interests	$28.3	$65.2	$ (36.9)	$18.2	$117.0	$ (98.8)

The major Non-Partnership results of operations relate to:

(1) Amortization of AOCI related to Versado hedges dropped down to the Partnership, and OCI related to terminated hedges.
(2) Depreciation on assets excluded from drop-down transactions and corporate administrative assets.
(3) General and administrative expenses retained by TRC related to its status as a public entity.
(4) Interest expense related to TRC debt obligations.
(5) TRC noncontrolling interest in the Partnership.

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Statements of Cash Flows – Partnership versus Non-Partnership

	Six Months Ended June 30,					
	2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
Cash flows from operating activities	(In millions)					
Net income (loss)	$56.2	$78.0	$ (21.8)	$112.6	$ 136.6	$ (24.0)
Adjustments to reconcile net income to net cash provided by operating activities:						
Amortization in interest expense (1)	8.1	8.0	0.1	9.5	9.1	0.4
Compensation on equity grants	6.8	3.0	3.8	8.8	1.6	7.2
Depreciation and amortization expense (2)	129.7	129.6	0.1	95.7	94.3	1.4
Accretion of asset retirement obligations	2.0	2.0	-	2.0	2.0	-
Deferred income tax expense (3)	0.7	0.8	(0.1)	2.7	0.8	1.9
Equity earnings, net of distributions	(4.5)	(4.5)	-	-	-	-
Risk management activities (4)	-	(0.1)	0.1	1.1	2.0	(0.9)
Loss (gain) on sale of assets	3.8	3.8	-	(0.1)	(0.1)	-
Loss on debt redemption	7.4	7.4	-	-	-	-
Changes in operating assets and liabilities (5)	(47.5)	(51.2)	3.7	(28.3)	(21.3)	(7.0)
Net cash provided by (used in) operating activities	162.7	176.8	(14.1)	204.0	225.0	(21.0)
Cash flows from investing activities						
Outlays for property, plant and equipment (2)	(444.5)	(444.5)	-	(238.7)	(238.4)	(0.3)
Investment in unconsolidated affiliate	-	-	-	(13.7)	(13.7)	-
Return of capital from unconsolidated affiliate	-	-	-	0.4	0.4	-
Other	(10.5)	(10.5)	-	0.9	0.9	-
Net cash used in investing activities	(455.0)	(455.0)	-	(251.1)	(250.8)	(0.3)
Cash flows from financing activities						
Loan Facilities - Partnership:						
Borrowings	1,305.0	1,305.0	-	725.0	725.0	-
Repayments	(1,181.4)	(1,181.4)	-	(683.0)	(683.0)	-
Accounts receivable securitization facility - Partnership						
Borrowings	207.7	207.7	-	-	-	-
Repayments	(82.4)	(82.4)	-	-	-	-
Loan Facilities - Non-Partnership:						
Borrowings (1)	30.0	-	30.0	-	-	-
Repayments (1)	(34.0)	-	(34.0)	-	-	-
Costs incurred in connection with debt financing arrangements (1)	(11.7)	(11.7)	-	(4.5)	(4.5)	-
Proceeds from sale of common units of the Partnership, net	231.2	235.2	(4.0)	115.2	168.4	(53.2)
Distributions to owners (6)	(125.9)	(189.5)	63.6	(105.1)	(147.0)	41.9

Dividends to common and common equivalent shareholders	(39.6)	-	(39.6)	(28.8)	-	(28.8)
Contributions (distributions) (7)	-	-	-	-	0.8	(0.8)
Net cash provided by (used in) financing activities	298.9	282.9	16.0	18.8	59.7	(40.9)
Net change in cash and cash equivalents	6.6	4.7	1.9	(28.3)	33.9	(62.2)
Cash and cash equivalents, beginning of period	76.3	68.0	8.3	145.8	55.6	90.2
Cash and cash equivalents, end of period	$82.9	$72.7	$ 10.2	$117.5	$ 89.5	$ 28.0

The major Non-Partnership cash flow items relate to:

(1) Cash and non-cash activity related to TRC and TRI debt obligations.

(2) Cash and non-cash activity related to corporate administrative assets.

(3) Reflects the Partnership's state margin tax, and TRC's federal and state taxes.

(4) Non-cash OCI hedge realizations related to predecessor operations.

(5) See Balance Sheet – Partnership versus Non-Partnership for a description of the Non-Partnership operating assets and liabilities.

(6) TRP cash distributions, including distributions received by TRC from the Partnership for its general partner interest, limited partner interest, IDRs, and net cash distributions related to noncontrolling interests.

(7) Contributions (distributions) to the Partnership.

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Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	(In millions, except operating statistics and price amounts)							
Revenues	$1,441.6	$1,319.1	$122.5	9 %	$2,839.4	$2,964.9	$(125.5)	(4 %)
Product purchases	1,176.4	1,074.6	101.8	9 %	2,313.9	2,458.8	(144.9)	(6 %)
Gross margin (1)	265.2	244.5	20.7	8 %	525.5	506.1	19.4	4 %
Operating expenses	96.1	77.3	18.8	24 %	182.2	148.9	33.3	22 %
Operating margin (2)	169.1	167.2	1.9	1 %	343.3	357.2	(13.9)	(4 %)
Depreciation and amortization expenses	65.7	48.3	17.4	36 %	129.7	95.7	34.0	36 %
General and administrative expenses	38.4	35.7	2.7	8 %	74.6	70.8	3.8	5 %
Other operating (income) expense	4.1	-	4.1	0 %	4.2	(0.1)	4.3	NM
Income from operations	60.9	83.2	(22.3)	(27%)	134.8	190.8	(56.0)	(29%)
Interest expense, net	(32.4)	(30.5)	(1.9)	6 %	(64.5)	(61.0)	(3.5)	6 %
Equity earnings	2.9	(0.2)	3.1	NM	4.5	1.9	2.6	NM
Loss on debt redemption	(7.4)	-	(7.4)	0 %	(7.4)	-	(7.4)	0 %
Other	6.5	(0.4)	6.9	NM	6.3	(0.3)	6.6	NM
Income tax expense	(8.0)	(8.6)	0.6	(7 %)	(17.5)	(18.8)	1.3	(7 %)
Net income	22.5	43.5	(21.0)	(48%)	56.2	112.6	(56.4)	(50%)
Less: Net income attributable to noncontrolling interests	7.5	34.9	(27.4)	(79%)	27.9	94.4	(66.5)	(70%)
Net income (loss) available to common shareholders	$15.0	$8.6	$6.4	74 %	$28.3	$18.2	$10.1	55 %
Operating statistics:								
Crude oil gathered, MBbl/d	38.3	-	38.3	-	34.9	-	34.9	-
Plant natural gas inlet, MMcf/d (3) (4)	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 (4)	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 the Partnership's 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 the Partnership's Operations" and "Non-GAAP Financial Measures."

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

(4)

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

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 ($148.1 million), higher commodity sales volumes ($50.7 million) and higher fee-based and other revenues ($19.7 million). Partially offsetting these favorable factors was lower realized prices on NGLs ($96.0 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 ($7.6 million), offset by higher interest capitalized on major capital projects ($5.9 million).

The June 2013 redemption of $100 million of the outstanding 6 % 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 is primarily due to lower Partnership earnings and increased incentive distributions. After adjusting for the impact of the IDRs, the weighted average percentages of the net income allocable to noncontrolling interest decreased from 57.7% for the three months ended June 30, 2012 to 4.2% for the three months ended June 30, 2013. Additionally, net income attributable to noncontrolling interests was $1.5 million lower primarily due to a weaker price environment at the Partnership's 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 ($417.9 million), which were partially offset by the impact of higher realized prices on natural gas and condensate ($196.2 million), the impact of higher commodity volumes ($51.6 million) and higher fee-based and other revenues ($44.6 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 ($11.2 million) and higher effective interest rates ($2.5 million), offset by higher interest capitalized on major capital projects ($10.2 million).

The June 2013 6 % Notes redemption noted above resulted in a $7.4 million loss on debt redemption.

The decrease in net income attributable to noncontrolling interests is primarily due to lower Partnership earnings and increased incentive distributions. After adjusting for the impact of the IDRs, the weighted average percentages of the net income allocable to noncontrolling interest decreased from 63.9% for the six months ended June 30, 2012 to 23.2% for the six months ended June 30, 2013. Additionally, net income attributable to noncontrolling interests was $6.8 million lower primarily due to a weaker price environment at the Partnership's Versado and VESCO joint ventures, which were affected by operational issues.

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Results of Operations—By Reportable Segment

We have segregated the following segment operating margins between Partnership and TRC Non-Partnership activities. Partnership activities have been presented on a common control accounting basis, which reflects the dropdown transactions between Targa and the Partnership as if they occurred in prior periods. TRC Non-Partnership segment results include certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected as such under GAAP in the Partnership common control results. See "—Financial Information – Partnership Versus Non-Partnership."

	Partnership						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	TRC Non-Partnership	Consolidated Operating Margin
	(In millions)						
Three Months Ended June 30,							
2013	$67.3	$ 16.7	$ 52.1	$ 27.4	$5.6	$ -	$ 169.1
2012	53.9	28.0	45.7	26.2	12.8	0.6	167.2
Six Months Ended June 30,							
2013	$121.1	$ 40.1	$ 108.6	$ 61.4	$12.3	$ (0.2)	$ 343.3
2012	126.9	74.3	88.7	52.4	14.1	0.8	357.2

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Results of Operations of the Partnership – By Reportable Segment

Gathering and Processing Segments

Field 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	$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.

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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.

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Marketing and Distribution

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 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 the Partnership’s hedging program on operating margin. It typically represents the cash settlements on the Partnership’s 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 the Partnership's commodity risk management activities is to manage its exposure to commodity price risk and reduce volatility in its operating cash flow due to fluctuations in commodity prices. The Partnership has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent of proceeds or liquids processing arrangements by entering into derivative instruments.

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The following table provides a breakdown of the Partnership's hedge revenue by product:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	2013 vs. 2012	2013	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.

Our Liquidity and Capital Resources

We have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common stockholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. See "Item 1A. Risk Factors." As of June 30, 2013, our interests in the Partnership consisted of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;

- all of the outstanding IDRs; and

- 12,945,659 of the 106,080,164 outstanding common units of the Partnership, representing a 12.2% limited partnership interest.

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

Our future cash flows will consist of distributions to us from our interests in the Partnership, from which we intend to make quarterly cash dividends to our stockholders from available cash. Based on our anticipated levels of distributions that we expect to receive from the Partnership, cash generated from this interest should provide sufficient resources to finance our operations, long-term debt and quarterly cash dividends for at least the next twelve months.

The impact on us of changes in the Partnership's distribution levels will vary depending on several factors, including the Partnership's total outstanding partnership interests on the record date for the distribution, the aggregate cash distributions made by the Partnership and the interests in the Partnership owned by us. If the Partnership increases distributions to its unitholders, including us, we would expect to increase dividends to our stockholders, although the timing and amount of such increased dividends, if any, will not necessarily be comparable to the timing and amount of the increase in distributions made by the Partnership. In addition, the level of distributions we receive and of dividends we pay to our stockholders may be affected by the various risks associated with an investment in us and the underlying business of the Partnership. Please read “Item 1A. Risk Factors” for more information about the risks that may impact your investment in us.

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

	July 29, 2013 (In millions)
Cash on hand	$ 109.2
Total availability under TRC's credit facility	150.0
Less: Outstanding borrowings under TRC's credit facility	(84.0)
Less: Outstanding letters of credit outstanding under TRC's credit facility	-
Total liquidity	$ 175.2

We have sufficient liquidity to satisfy over the next 12 years the $65.6 million tax liability we incurred as a result of our sales of assets to the Partnership.

Subsequent Event

On July 16, 2013, the Partnership announced that the board of directors of its general partner declared a quarterly distribution for the three months ended June 30, 2013 of $0.715 per common unit, or an annual rate of $2.86 per common unit. This distribution will be paid on August 14, 2013. Based on these current distribution rates, we will receive approximate distributions in future quarters and years of:

- $9.3 million or $37.0 million annually based on our common unit ownership in the Partnership;

- $24.6 million or $98.2 million annually based on our IDRs; and

- $2.0 million or $8.2 million annually based on our 2% general partner interests.

We intend to pay to our stockholders, on a quarterly basis, dividends equal to the cash the Partnership distributes to us based on our ownership of Partnership securities, less the expenses of being a public company, other general and administrative expenses, federal income taxes, capital contributions to the Partnership and reserves established by our board of directors.

The following table details the dividends declared and/or paid by us during the three months ended June 30, 2013:

Three Months Ended	Date Paid or to be Paid	Total Dividend Declared	Amount of Dividend Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
(In millions, except per share amounts)					
June 30, 2013	August 15, 2013	$ 22.5	$ 22.1	$ 0.4	$ 0.53250
March 31, 2013	May 16, 2013	21.0	20.6	0.4	0.49500
December 31, 2012	February 15, 2013	19.4	19.0	0.4	0.45750

(1) Represents accrued dividends on the restricted shares that are payable upon vesting.

The Partnership's Liquidity and Capital Resources

The Partnership's ability to finance its operations, including funding capital expenditures and acquisitions, meeting the Partnership's indebtedness obligations, refinancing its indebtedness and meeting its collateral requirements will depend on its ability to generate cash in the future. The Partnership's ability to generate cash is subject to a number of factors, some of which are beyond its 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.

The Partnership's 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. The Partnership's exposure to current credit conditions includes its credit facility, cash investments and counterparty performance risks. The Partnership continually monitors its liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

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As of July 29, 2013, the Partnership's 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

The Partnership may issue additional equity or debt securities under its 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 , the Partnership 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. We contributed $4.0 million to maintain our 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 the Partnership's capital needs, at its option, it has the ability to sell additional common units up to an aggregate amount of $35.6 million under the 2012 Shelf.

In April 2013, the Partnership filed with the SEC a universal shelf registration statement, the April 2013 Shelf, which provides it with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and its 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, the Partnership filed with the SEC a universal shelf registration statement (the July 2013 Shelf) that, subject to effectiveness at the time of use, allowing it 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, the Partnership redeemed the outstanding 11¼% Notes for $80.9 million, including accrued interest.

Risk Management

The Partnership evaluates counterparty risks related to its commodity derivative contracts and trade credit. The Partnership has all of its commodity derivatives with major financial institutions or major oil companies. Should any of these financial counterparties not perform, the Partnership may not realize the benefit of some of its hedges under lower commodity prices, which could have a material adverse effect on its results of operation. The Partnership sells its 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 the Partnership's cash flows, the Partnership has entered into derivative instruments to hedge the commodity price associated with a portion of its 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 the Partnership's ability to enter into future commodity derivative contracts.

The Partnership's 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 the Partnership currently expects to receive on those derivative contracts, creating this net asset position. Consequently, the Partnership's expected future receipts on derivative contracts are greater than its expected future payments. The Partnership accounts 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.

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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 the Partnership's reported total working capital are: (1) the Partnership's cash position; (2) liquids inventory levels and their valuation, which the Partnership closely manages; and (3) changes in the fair value of the current portion of derivative contracts.

For the six months ended June 30, 2013, the Partnership's working capital increased $44.9 million, primarily due to an increase of inventory in advance of the start-up of the Partnership's international export project coming on-line in the third quarter of this year, increased materials and supply inventory for the Badlands operations and a decrease in affiliate payables due to timing of reimbursements between the Partnership and us.

Based on the Partnership's anticipated levels of operations and absent any disruptive events, we believe that the Partnership's 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 its 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 the Partnership's capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While the Partnership's credit ratings have improved over time, these letters of credit reflect its non-investment grade status, as assigned to us by Moody's Investors Service, Inc. and Standard & Poor's Corporation, and counterparties' views of the Partnership's financial condition and ability to satisfy its performance obligations, as well as commodity prices and other factors. As of June 30, 2013, the Partnership 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 for the periods indicated. See "Statement of Cash Flows – Partnership versus Non-Partnership" for a detailed presentation of cash flow activity:

Six Months Ended June 30, 2013	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
Net cash provided by (used in):	(In millions)		
Operating activities	$162.7	$ 176.8	$ (14.1)
Investing activities	(455.0)	(455.0)	-
Financing activities	298.9	282.9	16.0
Six Months Ended June 30, 2012			
Net cash provided by (used in):			
Operating activities	$204.0	$ 225.0	$ (21.0)
Investing activities	(251.1)	(250.8)	(0.3)
Financing activities	18.8	59.7	(40.9)

Cash Flow from Operating Activities - Partnership

The Consolidated Statement of Cash Flows included in the Partnership's 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 the Partnership's 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.

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

	Six Months Ended June 30,		
	2013	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 Partnership's results of operations.

Cash Flow from Operating Activities - Non-Partnership

The operating activities of TRC – Non-Partnership are primarily related to interest, taxes and retained general and administrative expenses.

Cash Flow from Investing Activities - Partnership

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 - Partnership

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 6 % Senior Notes.

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Cash Flow Financing Activities - Non-Partnership

The decrease in net cash used in financing activities was primarily due to a decrease in the amount paid for the purchase of Partnership units of $47.8 million and an increase in distributions received of $21.7 million, partially offset by an increase in payments on the TRC Revolver of $4.0 million and an increase in dividends paid of $11.1 million.

Distributions from the Partnership and Dividends of TRC

The following table details the distributions declared and/or paid by the Partnership for the six months ended June 30, 2013 with respect to our 2% general partner interest, the associated IDRs and common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods:

For the Three Months Ended	Date Paid or to be Paid	Cash Distribution Per Limited Partner Unit	Cash Distributions Limited Partner Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (1)	Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
		(In millions, except per unit amounts)						
June 30, 2013	August 14, 2013	$0.7150	$9.3	$ 2.0	$24.6	$ 35.9	$0.53250	$ 22.5
March 31, 2013	May 15, 2013	0.6975	9.0	1.9	22.1	33.0	0.49500	$ 21.0
December 31, 2012	February 14, 2013	0.6800	8.8	1.8	20.1	30.7	0.45750	19.4

(1) Distributions to us comprise amounts attributable to our (i) limited partner units, (ii) general partner units, and (iii) IDRs.

Capital Requirements

The Partnership's 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 Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	2012 Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Capital expenditures:						
Expansion (1)	$399.2	$ 399.2	$ -	$206.5	$ 206.5	$ -
Maintenance	43.4	43.4	-	32.2	31.9	0.3
	442.6	442.6	-	238.7	238.4	0.3

Gross additions to property, plant and equipment						
Change in capital project payables and accruals	1.9	1.9	-	-	-	-
Cash outlays for capital projects	$444.5	$ 444.5	$ -	$238.7	$ 238.4	$ 0.3

(1) Excludes the Partnership's 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.

The Partnership estimates that its total growth capital expenditures for 2013 will be approximately $1.0 billion on a gross basis, and maintenance capital expenditures net to the Partnership's interest will be approximately $85 million. Given the Partnership's objective of growth through acquisitions, expansions of existing assets and other internal growth projects, the Partnership anticipates that over time they will invest significant amounts of capital to grow and acquire assets. The Partnership's future expansion capital expenditures may vary significantly based on investment opportunities. The Partnership expects to fund future capital expenditures with funds generated from its operations, borrowings under the TRP Revolver and proceeds from issuances of additional equity and debt offerings.

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Critical Accounting Policies and Estimates

The Partnership and 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, the Partnership established 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.

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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 exposure to market risk is largely derivative of the Partnership's exposure to market risk. The Partnership's principal market risks are its 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 its customers. Neither the Partnership nor we use risk sensitive instruments for trading purposes.

Commodity Price Risk

A significant portion of the Partnership's revenues are derived from percent-of-proceeds contracts under which it receives 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 the Partnership's control. The Partnership monitors these risks and enters into hedging transactions designed to mitigate the impact of commodity price fluctuations on its business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of the commodity risk management activities is to manage the exposure to commodity price risk and reduce volatility in the Partnership's operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of the Partnership's cash flows, as of June 30, 2013, the Partnership has hedged the commodity prices associated with a portion of its 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. The Partnership hedges a higher percentage of its expected equity volumes in the current year compared to future years, in which it hedges incrementally lower percentages of expected equity volumes. With swaps, the Partnership typically receives an agreed fixed price for a specified notional quantity of natural gas or NGLs and it pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its 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 its actual equity volumes, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership may buy calls in connection with swap positions to create a price floor with upside. The Partnership intends to continue to manage its 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.

The Partnership has tailored its hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of its physical equity volumes. The NGL hedges cover specific NGL products based upon the expected equity NGL composition. The Partnership believes 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 the Partnership's 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. The principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. The Partnership's 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 its senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its 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, the Partnership expects to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if a counterparty's exposure to the Partnership's credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in the Partnership's creditworthiness. A purchased put (or floor) transaction does not expose the Partnership's counterparties to credit risk, as the Partnership has no obligation to make future payments beyond the premium paid to enter into the transaction, however, the Partnership is 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.

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For all periods presented, the Partnership has entered into hedging arrangements for a portion of its 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 $5.5 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 $12.2 million and $14.1 million. The net hedge adjustments that impact our consolidated revenues (but do not affect the Partnership's revenues) include amortization of OCI related to hedges terminated and re-assigned upon the Partnership's acquisition of Versado in 2010, as well as OCI related to terminations of commodity derivatives in July 2008.

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

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Condensate					
Instrument		Price	Bbl/d		
Type	Index	$/Bbl	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 the Partnership to the risk of financial loss in certain circumstances. Generally, the Partnership's hedging arrangements provide 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 they have been hedged, the Partnership will receive less revenue on the hedged volumes than it would receive in the absence of hedges (other than with respect to purchased calls).

The Partnership accounts for the fair value of its 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. The Partnership values its 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 the Partnership is 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 13 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 TRC Revolver. The Partnership is exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under its TRP Revolver and its Securitization Facility. As of June 30, 2013, neither the Partnership nor we have any interest rate hedges. However, the Partnership or 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 TRC Revolver, the TRP Revolver and its Securitization Facility will also increase. As of June 30, 2013, the Partnership had $350.3 million in variable rate borrowings under its TRP Revolver and its Securitization Facility and we had variable rate borrowings of $78.0 million under our TRC Revolver. A hypothetical change of 100 basis points in the interest rate of variable rate debt would impact the Partnership's annual interest expense by $3.5 million and the TRC Non-Partnership annual interest expense by $0.8 million.

Counterparty Credit Risk

The Partnership is subject to risk of losses resulting from nonpayment or nonperformance by its 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, the Partnership's 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, the Partnership may sustain a loss and its 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.

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Customer Credit Risk

The Partnership extends credit to customers and other parties in the normal course of business. The Partnership has established various procedures to manage its credit exposure, including initial credit approvals, credit limits and terms, letters of credit and rights of offset. The Partnership also uses prepayments and guarantees to limit credit risk to ensure that its established credit criteria are met.

The Partnership has 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 the Partnership's 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.

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PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 14 – 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.

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Item 6. Exhibits.

Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.3	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)).
3.4	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)).
3.5	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)).
3.6	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)).
3.7	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)).
3.8	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)).
3.9	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.10	Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.9 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 28, 2011 (File No. 001-33303)).
3.11	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.1	

	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)).
10.2	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)).

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10.3	Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed July 18, 2013 (File No. 001-34991)).
10.4	Restricted Stock Agreement (incorporated by reference to Exhibit 10.2 to Targa Resources Corp.'s Current Report on Form 8-K filed July 18, 2013 (File No. 001-34991)).
10.5	Amendment to Restricted Stock Agreement (incorporated by reference to Exhibit 10.3 to Targa Resources Corp.'s Current Report on Form 8-K filed July 18, 2013 (File No. 001-34991)).
10.6	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)).
10.7	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)).
10.8	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)).
10.9	Targa Resources Partners LP Performance Unit Grant Agreement under the Targa Resources Corp. Long-Tern 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)).
10.10	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)).
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

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 Corp. (Registrant)
Date: August 2, 2013	By: /s/ Matthew J. Meloy Matthew J. Meloy Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)