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 (Loss)	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.

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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.

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.

		Distributions					
		Limited Partners	General Partner			Distributions to Targa Resources Corp.	Distributions per limited partner unit
Three Months Ended	Date Paid or to be Paid	Common	Incentive	2%	Total		
(In millions, except per unit amounts)							
June 30, 2013	August 14, 2013	$75.8	$24.6	$2.0	$102.4	$ 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:

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

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

	Gross Presentation		Pro forma Net Presentation	
June 30, 2013	Asset Position	Liability Position	Asset Position	Liability Position
Current position				
Counterparties with offsetting position	$20.6	$ 3.2	$17.4	$ -
Counterparties without offsetting position - assets	2.6	-	2.6	-
Counterparties without offsetting position - liabilities	-	0.6	-	0.6
	23.2	3.8	20.0	0.6
Long-term position				
Counterparties with offsetting position	4.1	0.8	3.3	-
Counterparties without offsetting position - assets	1.5	-	1.5	-
Counterparties without offsetting position - liabilities	-	1.0	-	1.0
	5.6	1.8	4.8	1.0
Total derivatives				
Counterparties with offsetting position	24.7	4.0	20.7	-
Counterparties without offsetting position - assets	4.1	-	4.1	-
Counterparties without offsetting position - liabilities	-	1.6	-	1.6
	$28.8	$ 5.6	$24.8	$ 1.6
December 31, 2012				

Current position				
Counterparties with offsetting position	$23.8	$ 7.4	$16.4	$ -
Counterparties without offsetting position - assets	5.5	-	5.5	-
Counterparties without offsetting position - liabilities	-	-	-	-
	29.3	7.4	21.9	-
Long-term position				
Counterparties with offsetting position	4.4	2.8	1.6	-
Counterparties without offsetting position - assets	0.7	-	0.7	-
Counterparties without offsetting position - liabilities	-	2.0	-	2.0
	5.1	4.8	2.3	2.0
Total derivatives				
Counterparties with offsetting position	28.2	10.2	18.0	-
Counterparties without offsetting position - assets	6.2	-	6.2	-
Counterparties without offsetting position - liabilities	-	2.0	-	2.0
	$34.4	$ 12.2	$24.2	$ 2.0

The fair value of 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)			
Derivatives in Cash Flow	Three Months Ended June 30,		Six Months Ended June 30,	
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, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 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, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 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

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(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				