Targa Resources Corp.
Form 10-Q
August 01, 2014

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, 2014

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 21, 2014, there were 42,158,448 shares of the registrant’s common stock, $0.001 par value, outstanding.

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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." in 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 various transactions with the Partnership;
- 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.” in this Quarterly Report, our Annual Report on Form 10-K for the year ended December 31, 2013 (“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)
Bcf	Billion cubic feet
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
LIBOR	London Interbank Offer Rate
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, 2014	December 31, 2013
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$75.9	$66.7
Trade receivables, net of allowances of $1.1 million and $1.1 million	682.6	658.8
Inventories	151.7	150.7
Deferred income taxes	4.0	0.1
Assets from risk management activities	2.0	2.0
Other current assets	23.0	18.9
Total current assets	939.2	897.2
Property, plant and equipment	6,165.6	5,758.4
Accumulated depreciation	(1,541.8)	(1,408.5)
Property, plant and equipment, net	4,623.8	4,349.9
Intangible assets, net	622.7	653.4
Long-term assets from risk management activities	1.6	3.1
Investment in unconsolidated affiliate	52.3	55.9
Other long-term assets	88.8	89.1
Total assets	$6,328.4	$6,048.6
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$806.4	$761.8
Deferred income taxes	-	0.6
Liabilities from risk management activities	12.5	8.0
Total current liabilities	818.9	770.4
Long-term debt	3,048.2	2,989.3
Long-term liabilities from risk management activities	2.5	1.4
Deferred income taxes	142.7	135.5
Other long-term liabilities	73.1	60.7
Commitments and contingencies (see Note 15)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300,000,000 shares authorized, 42,533,483 shares issued and 42,158,448 shares outstanding as of June 30, 2014, and 42,529,068 shares issued and 42,162,178 shares outstanding as of December 31, 2013)	-	-
Preferred stock ($0.001 par value, 100,000,000 shares authorized, no shares issued and outstanding as of June 30, 2014 and December 31, 2013)	-	-

Additional paid-in capital	149.8	151.6
Retained earnings	26.5	20.5
Accumulated other comprehensive income (loss)	(0.9)	(0.5)
Treasury stock, at cost (375,035 shares as of June 30, 2014 and 366,890 as of December 31, 2013)	(23.6)	(22.8)
Total Targa Resources Corp. stockholders' equity	151.8	148.8
Noncontrolling interests in subsidiaries	2,091.2	1,942.5
Total owners' equity	2,243.0	2,091.3
Total liabilities and owners' equity	$6,328.4	$6,048.6

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,	
	2014	2013	2014	2013
	(Unaudited)			
	(In millions, except per share amounts)			
Revenues	$2,061.9	$1,441.6	$4,414.8	$2,839.4
Costs and expenses:				
Product purchases	1,677.9	1,176.4	3,651.2	2,313.9
Operating expenses	106.6	96.1	210.9	182.2
Depreciation and amortization expenses	85.9	65.7	165.4	129.7
General and administrative expenses	41.6	38.4	79.5	74.6
Other operating (income) expense	(0.4)	4.1	(1.0)	4.2
Income from operations	150.3	60.9	308.8	134.8
Other income (expense):				
Interest expense, net	(35.7)	(32.4)	(69.6)	(64.5)
Equity earnings	4.2	2.9	9.1	4.5
Gain (loss) on debt redemptions and amendments	-	(7.4)	-	(7.4)
Other	(0.1)	6.5	-	6.3
Income before income taxes	118.7	30.5	248.3	73.7
Income tax (expense) benefit:				
Current	(16.6)	(7.6)	(40.5)	(16.8)
Deferred	1.1	(0.4)	2.4	(0.7)
	(15.5)	(8.0)	(38.1)	(17.5)
Net income	103.2	22.5	210.2	56.2
Less: Net income attributable to noncontrolling interests	76.8	7.5	164.2	27.9
Net income available to common shareholders	$26.4	$15.0	$46.0	$28.3
Net income available per common share - basic	$0.63	$0.36	$1.10	$0.68
Net income available per common share - diluted	$0.63	$0.36	$1.09	$0.67
Weighted average shares outstanding - basic	42.0	41.6	42.0	41.6
Weighted average shares outstanding - diluted	42.1	42.1	42.1	42.0

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30, 2014			2013		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income attributable to Targa Resources Corp.			$26.4			$15.0
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$(0.8)	$ 0.3	(0.5)	$3.0	$ (1.1)	1.9
Settlements reclassified to revenues	0.5	(0.2)	0.3	(0.8)	0.3	(0.5)
Interest rate swaps:						
Settlements reclassified to interest expense, net	0.1	(0.1)	-	0.3	(0.1)	0.2
Other comprehensive income (loss) attributable to Targa Resources Corp.	$(0.2)	$ -	(0.2)	$2.5	$ (0.9)	1.6
Comprehensive income attributable to Targa Resources Corp.			$26.2			$16.6
Net income attributable to noncontrolling interests			$76.8			$7.5
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	$(6.0)	$ -	(6.0)	$18.2	$ -	18.2
Settlements reclassified to revenues	4.0	-	4.0	(5.1)	-	(5.1)
Interest rate swaps:						
Settlements reclassified to interest expense, net	1.0	-	1.0	1.3	-	1.3
Other comprehensive income (loss) attributable to noncontrolling interests	$(1.0)	$ -	(1.0)	$14.4	$ -	14.4
Comprehensive income attributable to noncontrolling interests			75.8			21.9
Total comprehensive income			$102.0			$38.5

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Six Months Ended June 30, 2014			2013		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income attributable to Targa Resources Corp.			$46.0			$28.3
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$(2.4)	$ 0.9	(1.5)	$1.9	$ (0.7)	1.2
Settlements reclassified to revenues	1.4	(0.5)	0.9	(1.7)	0.7	(1.0)
Interest rate swaps:						
Settlements reclassified to interest expense, net	0.3	(0.1)	0.2	0.5	(0.2)	0.3
Other comprehensive income (loss) attributable to Targa Resources Corp.	$(0.7)	$ 0.3	(0.4)	$0.7	$ (0.2)	0.5
Comprehensive income attributable to Targa Resources Corp.			$45.6			$28.8
Net income attributable to noncontrolling interests			$164.2			$27.9
Other comprehensive loss attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	$(16.2)	$ -	(16.2)	$11.8	$ -	11.8
Settlements reclassified to revenues	9.4	-	9.4	(10.8)	-	(10.8)
Interest rate swaps:						
Settlements reclassified to interest expense, net	2.1	-	2.1	2.8	-	2.8
Other comprehensive income (loss) attributable to noncontrolling interests	$(4.7)	$ -	(4.7)	$3.8	$ -	3.8
Comprehensive income attributable to noncontrolling interests			159.5			31.7
Total comprehensive income			$205.1			$60.5

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Common Stock Shares	Common Stock Amount	Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares Shares	Treasury Shares Amount	Noncontrolling Interests	Total
	(Unaudited)								
	(In millions, except shares in thousands)								
Balance, December 31, 2013	42,162	$ -	$ 151.6	$ 20.5	$ (0.5)	367	$ (22.8)	$ 1,942.5	$ 2,091.3
Compensation on equity grants	4	-	2.6	-	-	-	-	4.9	7.5
Accrual of distribution equivalent rights	-	-	-	-	-	-	-	(1.4)	(1.4)
Repurchase of common stock	(8)	-	-	-	-	8	(0.8)	-	(0.8)
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	163.0	163.0
Impact of Partnership equity transactions	-	-	8.6	-	-	-	-	(8.6)	-
Dividends	-	-	(13.0)	(40.0)	-	-	-	-	(53.0)
Distributions	-	-	-	-	-	-	-	(168.7)	(168.7)
Other comprehensive income (loss)	-	-	-	-	(0.4)	-	-	(4.7)	(5.1)
Net income	-	-	-	46.0	-	-	-	164.2	210.2
Balance, June 30, 2014	42,158	$ -	$ 149.8	$ 26.5	$ (0.9)	375	$ (23.6)	$ 2,091.2	$ 2,243.0
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	-	-	-	-	-	-	-	(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

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2014	2013
	(Unaudited)	
	(In millions)	
Cash flows from operating activities		
Net income	$210.2	$56.2
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	6.9	8.1
Compensation on equity grants	7.5	6.8
Depreciation and amortization expense	165.4	129.7
Accretion of asset retirement obligations	2.2	2.0
Deferred income tax expense (benefit)	(2.4)	0.7
Equity earnings, net of distributions	-	(4.5)
Risk management activities	(0.7)	-
(Gain) loss on sale or disposition of assets	(1.2)	3.8
(Gain) loss on debt redemptions and amendments	-	7.4
Changes in operating assets and liabilities:		
Receivables and other assets	(31.7)	77.6
Inventory	(18.1)	(49.7)
Accounts payable and other liabilities	86.4	(56.5)
Net cash provided by operating activities	424.5	181.6
Cash flows from investing activities		
Outlays for property, plant and equipment	(419.6)	(463.4)
Return of capital from unconsolidated affiliate	3.6	-
Other, net	2.3	(10.5)
Net cash used in investing activities	(413.7)	(473.9)
Cash flows from financing activities		
Partnership loan facilities:		
Proceeds	950.0	1,305.0
Repayments	(850.0)	(1,181.4)
Partnership accounts receivable securitization facility:		
Borrowings	67.8	207.7
Repayments	(113.2)	(82.4)
Non-Partnership loan facilities:		
Proceeds	39.0	30.0
Repayments	(36.0)	(34.0)
Costs incurred in connection with financing arrangements	(1.7)	(11.7)
Distributions to owners	(168.7)	(125.9)
Proceeds from sale of common units of the Partnership	164.7	231.2
Dividends to common and common equivalent shareholders	(52.7)	(39.6)
Repurchase of common stock	(0.8)	-
Net cash provided by (used in) financing activities	(1.6)	298.9
Net change in cash and cash equivalents	9.2	6.6
Cash and cash equivalents, beginning of period	66.7	76.3
Cash and cash equivalents, end of period	$75.9	$82.9

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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

Note 1 — Organization

Targa Resources Corp. ("TRC") is a Delaware corporation formed in October 2005. Our common stock is listed on the New York Stock Exchange 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.

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, 2014 and 2013 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, 2014 are not necessarily indicative of the results that may be expected for the full year.

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, 2014, 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 an 11.3% 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 17 for an analysis of our and the Partnership's operations by business segment.

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The Partnership does not have any employees. We provide operational, general and administrative and other services to the Partnership, associated with the Partnership's existing assets and assets acquired from third parties. We perform centralized corporate functions for the Partnership, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing.

The Partnership Agreement between the Partnership and us, as general partner of the Partnership, governs the reimbursement of costs incurred on the behalf of the Partnership. We charge the Partnership for all the direct costs of the employees assigned to its operations, as well as all general and administrative support costs other than (1) costs attributable to our status as a separate reporting company and (2) our costs of providing management and support services to certain unaffiliated spun-off entities. The Partnership generally reimburses us monthly for cost allocations to the extent that we have made a cash outlay.

Reclassifications Affecting Statement of Cash Flows

In conjunction with the integration of Badlands into its financial reporting environment during 2013, the Partnership obtained further information about the acquisition date balance sheet, including the nature of the items comprising assumed Accounts payable and accrued liabilities. The Partnership determined that certain assumed liabilities related to purchases that, under its accounting policies, are considered capital in nature. Consequently, the Partnership made certain refinements to better reflect Badlands cash flow activity on a basis similar to that used for its other operations. As a result of these refinements, certain cash flow activity was presented in its 2013 Form 10-K on a basis different than that utilized for previous quarterly reporting during 2013. In preparing this quarterly report the Partnership has made certain measurement period reclassifications to the comparative Statement of Cash Flows for the six months ended June 30, 2013 to conform to the presentation of its Form 10-K, reclassifying $18.9 million related to capital expenditures previously included in Accounts payable and other liabilities of operating activities to Outlays for property, plant and equipment in investing activities, as shown below.

	Six Months Ended June 30, 2013		
Revised line items Consolidated Statement of Cash Flows	As Reported	Reclassification	Revised
Cash flows from operating activities			
Changes in operating assets and liabilities:			
Accounts payable and other liabilities	$(75.4)	$ 18.9	$(56.5)
Net cash provided by operating activities	162.7	18.9	181.6
Cash flows from investing activities:			
Changes in investing assets and liabilities:			
Outlays for property, plant and equipment	(444.5)	(18.9)	(463.4)
Net cash used in investing activities	(455.0)	(18.9)	(473.9)

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, 2013. There were no significant updates or revisions to these policies during the three months ended June 30, 2014.

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360), Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2014, limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have, or will have, a major effect on operations and financial results. The amendment requires expanded disclosures for discontinued operations and also requires additional disclosures regarding disposals of individually significant components that do not qualify as discontinued operations. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance. This amendment has no impact on our current disclosures, but will in the future if we dispose of any individually significant components.

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In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The update also creates a new Subtopic 340-40, Other Assets and Deferred Costs – Contracts with Customers, which provides guidance for the incremental costs of obtaining a contract with a customer and those costs incurred in fulfilling a contract with a customer that are not in the scope of another topic. The new revenue standard requires that entities should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entities expect to be entitled in exchange for those goods or services. To achieve that core principle, the standard requires a five-step process of identifying the contracts with customers, identifying the performance obligations in the contracts, determining the transaction price, allocating the transaction price to the performance obligations and recognizing revenue when, or as, the performance obligations are satisfied. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

The revenue recognition standard will be effective for us starting in the first quarter of 2017. Early adoption is not permitted. We must retroactively apply the new revenue recognition standard to transactions in all prior periods presented, but will have a choice between either (1) restating each prior period presented or (2) presenting a cumulative effect adjustment in our first quarter report in 2017. We have commenced our analysis of the new standard and its impact on our revenue recognition practices.

Note 4 — Inventories

The components of inventories consisted of the following:

	June 30, 2014	December 31, 2013
Commodities	$138.6	$ 136.4
Materials and supplies	13.1	14.3
	$151.7	$ 150.7

Note 5 — Property, Plant and Equipment and Intangible Assets

	June 30, 2014			December 31, 2013			
	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Estimated Useful Lives (In Years)
Gathering systems	$2,332.5	$ -	$ 2,332.5	$2,230.1	$ -	$ 2,230.1	5 to 20
Processing and fractionation facilities	1,824.7	6.6	1,831.3	1,598.0	6.6	1,604.6	5 to 25
Terminaling and storage facilities	863.3	-	863.3	715.2	-	715.2	5 to 25
Transportation assets	339.9	-	339.9	294.7	-	294.7	10 to 25
Other property, plant and equipment	130.8	0.2	131.0	121.3	0.2	121.5	3 to 25
Land	89.9	-	89.9	89.5	-	89.5	-
Construction in progress	577.7	-	577.7	702.8	-	702.8	-
Property, plant and equipment	6,158.8	6.8	6,165.6	5,751.6	6.8	5,758.4	

Accumulated depreciation	(1,539.4)	(2.4)	(1,541.8)	(1,406.2)	(2.3)	(1,408.5)	
Property, plant and equipment, net	$4,619.4	$ 4.4	$ 4,623.8	$4,345.4	$ 4.5	$ 4,349.9	
Intangible assets	$681.8	$ -	$ 681.8	$681.8	$ -	$ 681.8	20
Accumulated amortization	(59.1)	-	(59.1)	(28.4)	-	(28.4)	
Intangible assets, net	$622.7	$ -	$ 622.7	$653.4	$ -	$ 653.4	

Intangible assets consist of customer contracts and customer relationships acquired in the Partnership's Badlands 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.

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Amortization expense attributable to these intangible assets is recorded using a method that closely reflects the cash flow pattern underlying the intangible asset valuation. The estimated annual amortization expense for these intangible assets is approximately $61.4 million, $80.1 million, $88.3 million, $81.5 million and $67.8 million for each of years 2014 through 2018.

Note 6 — Asset Retirement Obligations

Our asset retirement obligations ("ARO") primarily relate to certain gas gathering pipelines and processing facilities, and are included in our Consolidated Balance Sheets as a component of other long-term liabilities. The changes in our aggregate asset retirement obligations are as follows:

	Six Months Ended June 30, 2014
Beginning of period	$ 50.9
Change in cash flow estimate	2.1
Accretion expense	2.2
End of period	$ 55.2

Note 7 – Investment in Unconsolidated Affiliate

At June 30, 2014, the Partnership's unconsolidated investment consisted of a 38.8% ownership interest in Gulf Coast Fractionators LP ("GCF").

The following table shows the activity related to the Partnership's investment in GCF:

	Six Months Ended June 30, 2014
Beginning of period	$ 55.9
Equity earnings	9.1
Cash distributions (1)	(12.7)
End of period	$ 52.3

(1) Includes $3.6 million distributions received in excess of the Partnership's share cumulative earnings that are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

Note 8 — Accounts Payable and Accrued Liabilities

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

	June 30, 2014	December 31, 2013

Commodities	$574.4	$ 520.8
Other goods and services	132.3	146.8
Interest	35.8	35.9
Compensation and benefits	37.9	40.3
Income and other taxes	20.9	10.2
Other	5.1	7.8
	$806.4	$ 761.8

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Note 9 — Debt Obligations

	June 30, 2014	December 31, 2013
Long-term debt:		
Non-Partnership obligations:		
TRC Senior secured revolving credit facility, variable rate, due October 2017 (1)	$87.0	$84.0
Obligations of the Partnership: (2)		
Senior secured revolving credit facility, variable rate, due October 2017 (3)	495.0	395.0
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	(26.7)	(28.0)
Senior unsecured notes, 6 % fixed rate, due August 2022	300.0	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0	625.0
Accounts receivable securitization facility, due December 2014 (4)	234.3	279.7
Total long-term debt	$3,048.2	$2,989.3
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)	94.6	86.8
	$94.6	$86.8

(1) As of June 30, 2014, availability under TRC's $150 million senior secured revolving credit facility was $63.0 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, 2014, availability under the Partnership's $1.2 billion senior secured revolving credit facility was $610.4 million.

(4) 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 borrowings on a long-term basis.

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, 2014:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC senior secured revolving credit facility	2.9%	2.9%
Partnership's senior secured revolving credit facility	1.9% - 4.5%	2.1%
Partnership's accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

As of June 30, 2014, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Note 10 — Partnership Units and Related Matters

Public Offerings of Common Units

During the six months ended June 30, 2014, the Partnership issued 3,024,901 common units under an equity distribution agreement entered into in August 2013 (the "August 2013 EDA"), receiving net proceeds of $163.0 million. We contributed $3.4 million to the Partnership to maintain our 2% general partner interest.

In May 2014, the Partnership entered into an additional equity distribution agreement under its July 2013 Shelf (the "May 2014 EDA"), with Barclays Capital Inc., Citigroup Global Markets Inc., Deutsche Bank Securities Inc., Jefferies LLC, Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC, UBS Securities LLC and Wells Fargo Securities, LLC, as its sales agents, pursuant to which the Partnership may sell, at its option, up to an aggregate of $400 million of its common units. For the six months ended June 30, 2014, there were no issuances under the May 2014 EDA.

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Subsequent Event

In July 2014, the Partnership issued 94,253 common units and 212,966 common units under the August 2013 EDA and May 2014 EDA, receiving total net proceeds of $20.9 million. We contributed $0.4 million to the Partnership to maintain our 2% general partner interest. As of July 21, 2014, approximately $385.4 million of the aggregate offering amount remained available for sale pursuant to the May 2014 EDA.

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 for the six months ended June 30, 2014.

		Distributions					
		Limited Partners	General Partner			Distributions to Targa	Distributions
Three Months Ended	Date Paid or to be Paid	Common	Incentive	2%	Total	Resources Corp.	per limited partner unit
(In millions, except per unit amounts)							
June 30, 2014	August 14, 2014	$89.5	$33.7	$2.5	$125.7	$ 46.3	$ 0.7800
March 31, 2014	May 15, 2014	87.2	31.7	2.4	121.3	44.0	0.7625
December 31, 2013	February 14, 2014	84.0	29.5	2.3	115.8	41.5	0.7475

Note 11 — Common Stock and Related Matters

The following table details the dividends declared and/or paid by us for the six months ended June 30, 2014:

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, 2014	August 15, 2014	$ 29.2	$ 29.0	$ 0.2	$0.69000
March 31, 2014	May 16, 2014	27.4	27.2	0.2	0.64750
December 31, 2013	February 18, 2014	25.6	25.5	0.1	0.60750

(1) Represents accrued dividends on restricted stock and restricted stock units that are payable upon vesting.

Dividends declared are recorded as a reduction of retained earnings to the extent of retained earnings that was available at the close of the prior quarter, with any excess recorded as a reduction of additional paid-in capital.

Note 12 — 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,	
	2014	2013	2014	2013
Net income	$103.2	$22.5	$210.2	$56.2
Less: Net income attributable to noncontrolling interests	76.8	7.5	164.2	27.9
Net income attributable to common shareholders	$26.4	$15.0	$46.0	$28.3
Weighted average shares outstanding - basic	42.0	41.6	42.0	41.6
Net income available per common share - basic	$0.63	$0.36	$1.10	$0.68
Weighted average shares outstanding	42.0	41.6	42.0	41.6
Dilutive effect of unvested stock awards	0.1	0.5	0.1	0.4
Weighted average shares outstanding - diluted	42.1	42.1	42.1	42.0
Net income available per common share - diluted	$0.63	$0.36	$1.09	$0.67

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Note 13 — 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 its Field Gathering and Processing segment and (ii) NGL and condensate equity volumes predominately in its Field Gathering and Processing segment and the LOU business unit in its Coastal Gathering and Processing segment that result from its percent-of-proceeds processing arrangements. These hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity 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 equity volumes using crude oil hedges that are based on the New York Mercantile Exchange (“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. Hedge ineffectiveness was immaterial for all periods presented.

At June 30, 2014, the notional volumes of the Partnership’s commodity hedges for equity volumes were:

Commodity	Instrument	Unit	2014	2015	2016
Natural Gas	Swaps	MMBtu/d	66,050	50,551	25,500
NGL	Swaps	Bbl/d	1,125	-	-
Condensate	Swaps	Bbl/d	2,450	-	-

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.

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.

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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, 2014		Fair Value as of December 31, 2013	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$1.2	$ 11.9	$2.0	$ 7.7
	Long-term	1.6	2.5	3.1	1.4
Total derivatives designated as hedging instruments		$2.8	$ 14.4	$5.1	$ 9.1
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$0.8	$ 0.6	$-	$ 0.3
Total derivatives not designated as hedging instruments		$0.8	$ 0.6	$-	$ 0.3
Total current position		$2.0	$ 12.5	$2.0	$ 8.0
Total long-term position		1.6	2.5	3.1	1.4
Total derivatives		$3.6	$ 15.0	$5.1	$ 9.4

The pro forma impact of reporting derivatives in the Consolidated Balance Sheets on a net basis is as follows:

	Gross Presentation		Pro forma Net Presentation	
June 30, 2014	Asset Position	Liability Position	Asset Position	Liability Position
Current position				
Counterparties with offsetting position	$1.4	$ 9.3	$-	$ 7.9
Counterparties without offsetting position - assets	0.6	-	0.6	-
Counterparties without offsetting position - liabilities	-	3.2	-	3.2
	2.0	12.5	0.6	11.1
Long-term position				
Counterparties with offsetting position	1.3	1.2	0.1	-
Counterparties without offsetting position - assets	0.3	-	0.3	-
Counterparties without offsetting position - liabilities	-	1.3	-	1.3
	1.6	2.5	0.4	1.3
Total derivatives				
Counterparties with offsetting position	2.7	10.5	0.1	7.9
Counterparties without offsetting position - assets	0.9	-	0.9	-
Counterparties without offsetting position - liabilities	-	4.5	-	4.5
	$3.6	$ 15.0	$1.0	$ 12.4
December 31, 2013				
Current position				
Counterparties with offsetting position	$1.9	$ 4.4	$-	$ 2.5
Counterparties without offsetting position - assets	0.1	-	0.1	-
Counterparties without offsetting position - liabilities	-	3.6	-	3.6
	2.0	8.0	0.1	6.1

Long-term position				
Counterparties with offsetting position	0.7	1.2	-	0.5
Counterparties without offsetting position - assets	2.4	-	2.4	-
Counterparties without offsetting position - liabilities	-	0.2	-	0.2
	3.1	1.4	2.4	0.7
Total derivatives				
Counterparties with offsetting position	2.6	5.6	-	3.0
Counterparties without offsetting position - assets	2.5	-	2.5	-
Counterparties without offsetting position - liabilities	-	3.8	-	3.8
	$ 5.1	$ 9.4	$ 2.5	$ 6.8

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.

The estimated fair value of the Partnership's derivative instruments was a net liability of $11.4 million as of June 30, 2014. 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.

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The following tables reflect amounts recorded in OCI and amounts reclassified from OCI to revenue and expense for the periods indicated:

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Derivatives in Cash Flow Hedging Relationships	2014	2013	2014	2013
Commodity contracts	$(6.8)	$21.2	$(18.6)	$13.7
	$(6.8)	$21.2	$(18.6)	$13.7

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2014	2013	2014	2013
Interest expense, net	$(1.1)	$(1.6)	$(2.4)	$(3.3)
Revenues	(4.5)	5.9	(10.8)	12.5
	$(5.6)	$4.3	$(13.2)	$9.2

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 commodity derivatives not designated as hedging instruments was immaterial for all periods presented.

As of June 30, 2014, the Partnership’s accumulated OCI balance includes net losses of $10.7 million related to contracts that will be settled and reclassified to revenue during the next 12 months.

The following table shows the deferred gains (losses) that are related to our consolidated accumulated OCI that will be reclassified into earnings through the end of 2016:

	June 30, 2014	December 31, 2013
Commodity hedges, before tax	$(1.5)	$ (0.5)
Commodity hedges, after tax	(0.9)	(0.3)
Interest rate hedges, before tax	-	(0.3)
Interest rate hedges, after tax	-	(0.2)

See Note 14 for additional disclosures related to derivative instruments and hedging activities.

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Note 14 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities (“financial instruments”). Derivative financial instruments are reported at fair value in our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost in our Consolidated Balance Sheets, with fair value measurements for these instruments provided as supplemental information.

The following are 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 swaps 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 are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This financial position reflects the present value, adjusted for counterparty credit risk, of the amount the Partnership expects to receive or pay 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 $33.0 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 $10.1 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. As of June 30, 2014, the contingent consideration fully expired with no payment due. 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 Accounts Receivable Securitization Facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and

- 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 of financial assets and liabilities 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 Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	June 30, 2014				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value					
Assets from commodity derivative contracts (1)	$3.5	$3.5	$ -	$3.0	$0.5
Liabilities from commodity derivative contracts (1)	14.9	14.9	-	12.4	2.5
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	75.9	75.9	-	-	-
TRC Senior secured revolving credit facility	87.0	87.0	-	87.0	-
Partnership's Senior secured revolving credit facility	495.0	495.0	-	495.0	-
Partnership's Senior unsecured notes	2,231.9	2,369.0	-	2,369.0	-
Partnership's accounts receivable securitization facility	234.3	234.3	-	234.3	-

(1) The fair value of the derivative contracts in this table is presented on a different basis than the balance sheet presentation as disclosed in Note 13. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the balance sheet presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for balance sheet classification purposes.

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

As of June 30, 2014, we reported certain of the Partnership's natural gas 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 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, 2014, the Partnership had fifteen natural gas 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 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.

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 Asset/ (Liability)
Balance, December 31, 2013	$ 0.7
Settlements included in Revenue	(2.7)
Balance, June 30, 2014	$ (2.0)

There has been no transfer of assets or liabilities among the three levels of the fair value hierarchy during the six months ended June 30, 2014.

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Note 15 — 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.

Contingent Consideration

Pursuant to the Membership Interest Purchase and Sale Agreement (“MIPSA”), the Partnership acquisition of Badlands was subject to a contingent payment of $50 million (the “contingent consideration”) if aggregate crude oil gathering volumes exceeded 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. 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. As of June 30, 2013, the contingent consideration was re-estimated to be $9.1 million, a decrease of $6.2 million, reflecting at that time management’s updated assessment. The contingent period expired June 2014, with no contingent thresholds obtained.

Note 16 - Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2014	2013
Cash:		
Interest paid, net of capitalized interest (1)	$62.7	$55.9
Income taxes paid, net of refunds	35.9	23.1
Non-cash Investing and Financing balance sheet movements:		
Deadstock commodity inventories transferred to property, plant and equipment	15.9	22.2
Accrued dividends on unvested equity awards	0.3	0.7
Change in receivables from equity issuances	0.3	32.8
Change in capital expenditure accruals	30.1	20.8
Transfers from materials and supplies inventory to property, plant and equipment	1.4	-
Change in ARO liability and property, plant and equipment due to revised future ARO cash flow estimate	2.1	1.4

(1) Interest capitalized on major projects was $11.5 million and $14.8 million for the six months ended June 30, 2014 and 2013.

Note 17 — 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; and assets used for crude oil gathering and terminaling. The Field Gathering and Processing segment's assets are located in North Texas, the Permian Basin of West Texas and Southeast New Mexico and in North Dakota. 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.

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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, including services to LPG exporters, 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. 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, and Galena Park, Texas and Lake Charles, 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 for resale 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; (4) providing propane, butane and services to LPG exporters; and (5) 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.

Segment information is shown in the following tables. We have segregated the following segment information between Partnership and non-Partnership activities.

	Three Months Ended June 30, 2014							
	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	$62.9	$ 89.7	$28.9	$ 1,644.7	$(4.0)	$ -	$ -	$ 1,822.2
Fees from midstream services	43.1	10.5	72.7	113.4	-	-	-	239.7
	106.0	100.2	101.6	1,758.1	(4.0)	-	-	2,061.9
Intersegment revenues								
Sales of commodities	381.9	163.4	0.8	137.0	-	(683.1)	-	-
Fees from midstream services	1.1	-	72.3	7.6	-	(81.0)	-	-
	383.0	163.4	73.1	144.6	-	(764.1)	-	-
Revenues	$489.0	$ 263.6	$174.7	$ 1,902.7	$(4.0)	$ (764.1)	$ -	$ 2,061.9
Operating margin	$97.7	$ 21.8	$108.6	$ 53.3	$(4.0)	$ -	$ -	$ 277.4
Other financial information:								
Total assets (1)	$3,338.6	$ 377.0	$1,606.0	$ 799.4	$3.5	$ 115.5	$ 88.4	$ 6,328.4
Capital expenditures	$128.4	$ 3.1	$67.5	$ 15.5	$-	$ 1.0	$ -	$ 215.5

(1) Corporate assets primarily include investment in unconsolidated subsidiaries and debt issuance costs associated with our long-term debt.

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	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	$ 1,142.3	$5.6	$ -	$ -	$ 1,327.5
Fees from midstream services	22.6	9.8	47.4	34.3	-	-	-	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

	Six Months Ended June 30, 2014							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Total
Revenues								
Sales of commodities	$108.7	$ 190.2	$49.9	$ 3,628.3	$(10.1)	$ -	$ -	$3,967.0
Fees from midstream services	83.9	18.2	140.8	204.9	-	-	-	447.8
	192.6	208.4	190.7	3,833.2	(10.1)	-	-	4,414.8
Intersegment revenues								
Sales of commodities	782.2	340.4	1.4	267.5	-	(1,391.5)	-	-
Fees from midstream services	2.1	-	138.6	15.4	-	(156.1)	-	-
	784.3	340.4	140.0	282.9	-	(1,547.6)	-	-
Revenues	$976.9	$ 548.8	$330.7	$ 4,116.1	$(10.1)	$ (1,547.6)	$ -	$4,414.8
Operating margin	$191.7	47.8	205.4	117.9	(10.1)	(0.0)	$ -	$552.7
Other financial information:								
Total assets	$3,338.6	377.0	1,606.0	799.4	3.5	115.5	$ 88.4	$6,328.4
Capital expenditures	$227.3	7.4	136.1	18.6	-	1.5	$ -	$390.9

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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	Total
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

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,	
	2014	2013	2014	2013
Sales of commodities:				
Natural gas	$358.3	$347.6	$750.9	$602.8
NGL	1,398.5	896.7	3,109.3	1,860.3
Condensate	41.8	33.0	70.1	60.1
Petroleum products	28.2	44.2	48.3	75.5
Derivative activities	(4.6)	6.0	(11.6)	12.4
	1,822.2	1,327.5	3,967.0	2,611.1
Fees from midstream services:				
Fractionating and treating	51.7	27.9	98.2	55.1
Storage, terminaling, transportation and export	124.3	47.1	223.9	107.2
Gathering and processing	48.0	26.9	90.6	45.4
Other	15.7	12.2	35.1	20.6
	239.7	114.1	447.8	228.3
Total revenues	$2,061.9	$1,441.6	$4,414.8	$2,839.4

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,	
	2014	2013	2014	2013
Reconciliation of operating margin to net income:				

Operating margin	$277.4	$169.1	$552.7	$343.3
Depreciation and amortization expense	(85.9)	(65.7)	(165.4)	(129.7)
General and administrative expense	(41.6)	(38.4)	(79.5)	(74.6)
Interest expense, net	(35.7)	(32.4)	(69.6)	(64.5)
Other, net	4.5	(2.1)	10.1	(0.8)
Income tax expense	(15.5)	(8.0)	(38.1)	(17.5)
Net income	$103.2	$22.5	$210.2	$56.2

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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, 2013 ("Annual Report"), as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources 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.

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 United States provider of midstream natural gas and NGL services, with a growing presence in crude oil gathering and petroleum terminaling. 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 financial results presented in our consolidated financial statements will differ from the financial statements of the Partnership primarily due to the effects of:

- our separate debt obligations;
- federal income taxes;
- certain retained general and administrative costs applicable to us as a public company;
- certain administrative assets and liabilities incumbent as a provider of operational and support services to the Partnership;
- certain non-operating assets and liabilities that we retained;

- Partnership distributions and earnings allocable to third-party common unitholders which are included in non-controlling interest in our statements; and

- Partnership distributions applicable to our General Partner interest, Incentive Distribution Rights and investment in Partnership common units. While these are eliminated when preparing our consolidated financial statements, they nonetheless are the primary source of cash flow that supports the payment of dividends to our stockholders.

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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 and NGL services, with a growing presence in crude oil gathering and petroleum terminaling in the United States. In connection with these business activities, the Partnership buys and sells natural gas, NGLs and NGL products, crude oil, condensate and refined products.

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, including services to LPG exporters;
- 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; and assets used for crude oil gathering and terminaling. The Field Gathering and Processing segment's assets are located in North Texas, the Permian Basin of West Texas and Southeast New Mexico and in North Dakota. 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 the storing, terminaling, distributing and marketing of NGLs, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses including services to LPG exporters. 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 exporting LPGs; and storing and terminaling of refined petroleum products. 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 and Galena Park, Texas and in Lake Charles, 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 for resale 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; (4) providing propane, butane and services to LPG exporters; and (5) 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.

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

2014 Year-to-Date Developments

International Export Expansion Project

During the second quarter of 2014, as part of Phase II of the International Export Expansion Project, the Partnership added incremental capacity and operational efficiencies to Phase I of this project via the addition of refrigeration and the completion of another dock. Phase II is expected to be fully operational in the third quarter of 2014 with the addition of a de-ethanizer, which is the final stage of the expansion.

Field Gathering and Processing Segment Expansion

In May 2014, the Partnership commenced commercial operations of the 200 MMcf/d cryogenic Longhorn processing plant in North Texas, and in June 2014, the Partnership commenced commercial operations of the 200 MMcf/d cryogenic High Plains processing plant in the Permian Basin. These plants will enable North Texas and SAOU to meet increasing production from continued producer activity in North Texas and the eastern side of the Permian Basin.

Condensate Splitter

On March 31, 2014, the Partnership announced the approval to construct a condensate splitter at its Channelview Terminal on the Houston Ship Channel. The condensate splitter is supported by a long-term fee based arrangement with Noble Americas Corp., a subsidiary of Noble Group Ltd.

The approximately $115 million project will have the capability to split approximately 35,000 barrels per day of condensate into its various components, including naptha, kerosene, gas oil, jet fuel and liquefied petroleum gas, and will provide segregated storage for the condensate and components. The project is expected to be completed approximately 18 months after all permits have been obtained.

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In July 2014, the Partnership received approval for the construction of a 100,000 barrel per day fractionation expansion in Mont Belvieu, Texas. The 100,000 barrel per day expansion will be fully integrated with the Partnership's existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as its LPG export terminal at Galena Park, Texas on the Houston Ship Channel.

All environmental and internal approvals required to commence construction of the expansion are in place, and we expect completion of construction in mid-2016. Construction of the expansion will proceed without disruption to existing operations, and we estimate that total capital expenditures for the expansion and the related infrastructure enhancements at Mont Belvieu should approximate $385 million.

Financing Activities

Through July 2014, pursuant to the August 2013 EDA and the May 2014 EDA, the Partnership issued a total of 3,332,120 common units representing total net proceeds of $183.9 million, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes. We contributed $3.8 million to the Partnership to maintain our 2% general partner interest during this period.

On July 21, 2014, Standard & Poor's Ratings Services ("S&P") raised the Partnership's corporate credit rating to 'BB+' from 'BB'. At the same time, S&P raised the credit rating on the Partnership's senior unsecured notes to 'BB+' from 'BB'.

Recent Accounting Pronouncements

In April 2014, the FASB issued ASU No. 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360), Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2014, limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have, or will have, a major effect on operations and financial results. The amendment requires expanded disclosures for discontinued operations and also requires additional disclosures regarding disposals of individually significant components that do not qualify as discontinued operations. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance. This amendment has no impact on our current disclosures, but will in the future if we dispose of any individually significant components.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The update also creates a new Subtopic 340-40, Other Assets and Deferred Costs – Contracts with Customers, which provides guidance for the incremental costs of obtaining a contract with a customer and those costs incurred in fulfilling a contract with a customer that are not in the scope of another topic. The new revenue standard requires that entities should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entities expect to be entitled in exchange for those goods or services. To achieve that core principle, the standard requires a five step process of identifying the contracts with customers, identifying the performance obligations in the contracts, determining the transaction price, allocating the transaction price to the performance obligations, and recognizing revenue when, or as, the performance obligations are satisfied. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

The revenue recognition standard will be effective for us starting in the first quarter of 2017. Early adoption is not permitted. We must retroactively apply the new revenue recognition standard to transactions in all prior periods presented, but will have a choice between either (1) restating each prior period presented or (2) presenting a cumulative effect adjustment in our first quarter report in 2017. We have commenced our analysis of the new standard and its impact on our revenue recognition practices.

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 direct operating activities separate 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 or not 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.

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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.

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,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of Net Income attributable to Targa Resources Corp. to Distributable Cash Flow				
Net income of Targa Resources Corp.	$103.2	$22.5	$210.2	$56.2
Less: Net income of Targa Resources Partners LP	(120.9)	(32.7)	(252.2)	(78.0)
Net loss for TRC Non-Partnership	(17.7)	(10.2)	(42.0)	(21.8)
TRC Non-Partnership income tax expense	14.2	7.1	35.7	15.8
Distributions from the Partnership (1)	46.3	35.9	90.3	68.9
Non-cash loss (gain) on hedges	-	0.1	-	0.1
Depreciation - Non-Partnership assets	0.1	-	0.1	0.1
Current cash tax expense (2)	(17.1)	(5.9)	(34.1)	(13.4)
Taxes funded with cash on hand (3)	2.9	2.5	5.9	5.0
Distributable cash flow	$28.7	$29.5	$55.9	$54.7

(1) Includes current quarter distributions.

(2) 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, 2014 and 2013, and includes $(2.7) million and $2.3 million adjustments to account for differences between taxes from cash available to distribute and book taxes for the three and six months ended June 30, 2014.

(3) 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.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Targa Resources Corp. Distributable Cash Flow				
Distributions declared by Targa Resources Partners LP associated with:				
General Partner Interests	$2.5	$2.0	$4.9	$3.9
Incentive Distribution Rights	33.7	24.6	65.4	46.7
Common Units	10.1	9.3	20.0	18.3
Total distributions declared by Targa Resources Partners LP	46.3	35.9	90.3	68.9
Income (expenses) of TRC Non-Partnership				
General and administrative expenses	(2.5)	(2.3)	(4.7)	(4.3)
Interest expense, net	(0.8)	(0.8)	(1.5)	(1.5)
Current cash tax expense (1)	(17.1)	(5.9)	(34.1)	(13.4)
Taxes funded with cash on hand (2)	2.9	2.5	5.9	5.0
Other income (expense)	(0.1)	0.1	-	-
Distributable cash flow	$28.7	$29.5	$55.9	$54.7

(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, 2014 and 2013, and includes $(2.7) million and $2.3 million adjustments to account for differences between taxes from cash available to distribute and book taxes for the three and six months ended June 30, 2014.

(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 natural gas, NGLs, crude and condensate the Partnership sells, and (ii) the costs associated with conducting the Partnership's operations, including the costs of wellhead natural gas, crude and mixed NGLs that the Partnership purchases as well as operating, 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.

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, has been increasing the percentage of our revenues that are fee-based. 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 supply 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.

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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 reduces 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 its 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.

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 subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval. The Partnership has seen a substantial increase in its total capital spent since 2010 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 by the Partnership's contract mix and commodity hedging program. The Partnership defines Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate, crude 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 and crude 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. The gross margin impacts of cash flow hedge settlements are reported in Other.

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 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 management and by external users of the Partnership's financial statements, including investors and commercial banks, to assess:

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- 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 attributable to Targa Resources Partners LP 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; changes in the fair value of the Badlands acquisition contingent consideration and the non-controlling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by the Partnership and by external users of its 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.

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 attributable to Targa Resources Partners LP. 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, thereby diminishing its utility.

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 risk management activities related to derivative instruments, 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.

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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 or not 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, the Partnership's 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.

The following tables reconcile the non-GAAP financial measures of the Partnership used by management to the most directly comparable GAAP measures for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	$384.0	$265.2	$763.6	$525.6
Operating expenses	(106.6)	(96.1)	(210.9)	(182.1)
Operating margin	277.4	169.1	552.7	343.5
Depreciation and amortization expenses	(85.8)	(65.7)	(165.3)	(129.6)
General and administrative expenses	(39.1)	(36.1)	(74.8)	(70.3)
Interest expense, net	(34.9)	(31.6)	(68.1)	(63.0)
Income tax (expense) benefit	(1.3)	(0.9)	(2.4)	(1.8)
Gain (loss) on sale or disposition of assets	0.5	(3.9)	1.2	(3.8)
Gain (loss) on debt redemptions and amendments	-	(7.4)	-	(7.4)
Change in contingent consideration	-	6.5	-	6.2
Other, net	4.1	2.7	8.9	4.2
Targa Resources Partners LP net income	$120.9	$32.7	$252.2	$78.0

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	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	$140.4	$5.1	$456.8	$195.7
Net income attributable to noncontrolling interests	(12.1)	(6.4)	(21.0)	(12.8)
Interest expense, net (1)	31.6	27.6	61.4	55.0
Current income tax expense (benefit)	1.0	0.5	1.7	1.0
Other (2)	(6.8)	(2.2)	(14.0)	(6.2)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivables, inventories and other assets	152.3	90.0	41.1	(31.5)
Accounts payable and other liabilities	(80.0)	11.9	(67.8)	57.6
Targa Resources Partners LP Adjusted EBITDA	$226.4	$126.5	$458.2	$258.8

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $3.3 million and $4.0 million for three months ended June 30, 2014 and 2013, and $6.7 million and $8.0 million for the six months ended June 30, 2014 and 2013.

(2) Includes equity earnings from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations, amortization of stock-based compensation and noncontrolling interest portion of depreciation and amortization expenses.

	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
	(In millions)			
Reconciliation of Net Income attributable to Targa Resources Partners LP to Adjusted EBITDA:				
Net income attributable to Targa Resources Partners LP	$108.8	$26.3	$231.2	$65.2
Interest expense, net	34.9	31.6	68.1	63.0
Income tax expense (benefit)	1.3	0.9	2.4	1.8
Depreciation and amortization expenses	85.8	65.7	165.3	129.6
(Gain) loss on sale or disposition of assets	(0.5)	3.9	(1.2)	3.8
(Gain) loss on debt redemptions and amendments	-	7.4	-	7.4
Change in contingent consideration	-	(6.5)	-	(6.2)
Risk management activities	(0.4)	0.2	(0.7)	0.1
Noncontrolling interests adjustment (1)	(3.5)	(3.0)	(6.9)	(5.9)
Targa Resources Partners LP Adjusted EBITDA	$226.4	$126.5	$458.2	$258.8

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

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of Net Income attributable to Targa Resources Partners LP to Distributable Cash flow:				
Net income attributable to Targa Resources Partners LP	$108.8	$26.3	$231.2	$65.2
Depreciation and amortization expenses	85.8	65.7	165.3	129.6
Deferred income tax expense (benefit)	0.3	0.4	0.7	0.8
Amortization in interest expense	3.3	4.0	6.7	8.0
(Gain) loss on debt redemptions and amendments	-	7.4	-	7.4
Change in contingent consideration	-	(6.5)	-	(6.2)
(Gain) loss on sale or disposition of assets	(0.5)	3.9	(1.2)	3.8
Risk management activities	(0.4)	0.2	(0.7)	0.1
Maintenance capital expenditures	(20.0)	(21.8)	(33.7)	(43.4)
Other (1)	(2.0)	(0.6)	(3.9)	(0.6)
Targa Resources Partners LP distributable cash flow	$175.3	$79.0	$364.4	$164.7

(1) Includes 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 Sheets, 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, 2014			December 31, 2013		
	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)	$75.9	$67.3	$ 8.6	$66.7	$57.5	$ 9.2
Trade receivables, net	682.6	682.2	0.4	658.8	658.6	0.2
Inventory	151.7	151.7	-	150.7	150.7	-
Deferred income taxes (2)	4.0	-	4.0	0.1	-	0.1
Assets from risk management activities	2.0	2.0	-	2.0	2.0	-
Other current assets (1)	23.0	5.5	17.5	18.9	7.1	11.8
Total current assets	939.2	908.7	30.5	897.2	875.9	21.3
Property, plant and equipment, at cost	6,165.6	6,158.8	6.8	5,758.4	5,751.6	6.8
Accumulated depreciation	(1,541.8)	(1,539.4)	(2.4)	(1,408.5)	(1,406.2)	(2.3)
Property, plant and equipment, net	4,623.8	4,619.4	4.4	4,349.9	4,345.4	4.5
Intangible assets, net	622.7	622.7	-	653.4	653.4	-
Long-term assets from risk management activities	1.6	1.6	-	3.1	3.1	-
Other long-term assets (2)	141.1	87.6	53.5	145.0	93.6	51.4
Total assets	$6,328.4	$6,240.0	$ 88.4	$6,048.6	$5,971.4	$ 77.2
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (3)	$806.4	$769.0	$ 37.4	$761.8	$721.2	$ 40.6
Affiliate payable (receivable) (4)	-	43.7	(43.7)	-	52.4	(52.4)
Deferred income taxes (5)	-	-	-	0.6	-	0.6
Liabilities from risk management activities	12.5	12.5	-	8.0	8.0	-
Total current liabilities	818.9	825.2	(6.3)	770.4	781.6	(11.2)
Long-term debt	3,048.2	2,961.2	87.0	2,989.3	2,905.3	84.0
Long-term liabilities from risk management activities	2.5	2.5	-	1.4	1.4	-
Deferred income taxes (5)	142.7	13.4	129.3	135.5	12.1	123.4
Other long-term liabilities (6)	73.1	56.9	16.2	60.7	52.6	8.1
Total liabilities	4,085.4	3,859.2	226.2	3,957.3	3,753.0	204.3
Total owners' equity	2,243.0	2,380.8	(137.8)	2,091.3	2,218.4	(127.1)
Total liabilities and owners' equity	$6,328.4	$6,240.0	$ 88.4	$6,048.6	$5,971.4	$ 77.2

The major Non-Partnership balance sheet items relate to:

(1) Corporate assets consisting of cash and prepaid insurance.

(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.

(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,					
	2014			2013		
	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	$ 2,061.9	$ 2,061.9	$ -	$ 1,441.6	$ 1,441.6	$ -
Costs and expenses:						
Product purchases	1,677.9	1,677.9	-	1,176.4	1,176.4	-
Operating expenses	106.6	106.6	-	96.1	96.1	-
Depreciation and amortization expenses (1)	85.9	85.8	0.1	65.7	65.7	-
General and administrative expenses (2)	41.6	39.1	2.5	38.4	36.1	2.3
Other operating (income) expense	(0.4)	(0.4)	-	4.1	4.1	-
Income from operations	150.3	152.9	(2.6)	60.9	63.2	(2.3)
Other income (expense):						
Interest expense, net - third party (3)	(35.7)	(34.9)	(0.8)	(32.4)	(31.6)	(0.8)
Equity earnings	4.2	4.2	-	2.9	2.9	-
Gain (loss) on debt redemptions and amendments	-	-	-	(7.4)	(7.4)	-
Other income (expense)	(0.1)	-	(0.1)	6.5	6.5	-
Income (loss) before income taxes	118.7	122.2	(3.5)	30.5	33.6	(3.1)
Income tax (expense) benefit (4)	(15.5)	(1.3)	(14.2)	(8.0)	(0.9)	(7.1)
Net income (loss)	103.2	120.9	(17.7)	22.5	32.7	(10.2)
Less: Net income attributable to noncontrolling interests (5)	76.8	12.1	64.7	7.5	6.4	1.1
Net income (loss) after noncontrolling interests	$ 26.4	$ 108.8	$ (82.4)	$ 15.0	$ 26.3	$ (11.3)

The major Non-Partnership results of operations relate to:

(1) Depreciation on assets excluded from drop-down transactions.

(2) General and administrative expenses retained by TRC related to its status as a public entity.

(3) Interest expense related to TRC debt obligations.

(4) Reflects TRC's federal and state income taxes.

(5) TRC noncontrolling interest in the net income of the Partnership.

	Six Months Ended June 30,					
	2014			2013		
	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	$ 4,414.8	$ 4,414.8	$ -	$ 2,839.4	$ 2,839.5	$ (0.1)
Costs and expenses:						
Product purchases	3,651.2	3,651.2	-	2,313.9	2,313.9	-
Operating expenses	210.9	210.9	-	182.2	182.1	0.1
Depreciation and amortization expenses (1)	165.4	165.3	0.1	129.7	129.6	0.1

General and administrative expenses (2)	79.5	74.8	4.7	74.6	70.3	4.3
Other operating (income) expense	(1.0)	(1.0)	-	4.2	4.2	-
Income from operations	308.8	313.6	(4.8)	134.8	139.4	(4.6)
Other income (expense):						
Interest expense, net - third party (3)	(69.6)	(68.1)	(1.5)	(64.5)	(63.0)	(1.5)
Equity earnings	9.1	9.1	-	4.5	4.5	-
Gain (loss) on debt redemptions and amendments	-	-	-	(7.4)	(7.4)	-
Other income (expense)	-	-	-	6.3	6.3	-
Income (loss) before income taxes	248.3	254.6	(6.3)	73.7	79.8	(6.1)
Income tax (expense) benefit (4)	(38.1)	(2.4)	(35.7)	(17.5)	(1.8)	(15.7)
Net income (loss)	210.2	252.2	(42.0)	56.2	78.0	(21.8)
Less: Net income attributable to noncontrolling interests (5)	164.2	21.0	143.2	27.9	12.8	15.1
Net income (loss) after noncontrolling interests	$46.0	$231.2	$(185.2)	$28.3	$65.2	$(36.9)

The major Non-Partnership results of operations relate to:
(1) Depreciation on assets excluded from drop-down transactions.
(2) General and administrative expenses retained by TRC related to its status as a public entity.
(3) Interest expense related to TRC debt obligations.
(4) Reflects TRC's federal and state income taxes.
(5) TRC noncontrolling interest in the net income of the Partnership.

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Statements of Cash Flows – Partnership versus Non-Partnership

	Six Months Ended June 30, 2014			2013		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Cash flows from operating activities						
Net income (loss)	$210.2	$ 252.2	$ (42.0)	$56.2	$78.0	$ (21.8)
Adjustments to reconcile net income to net cash provided by operating activities:						
Amortization in interest expense (1)	6.9	6.7	0.2	8.1	8.0	0.1
Compensation on equity grants (2)	7.5	4.9	2.6	6.8	3.0	3.8
Depreciation and amortization expense	165.4	165.3	0.1	129.7	129.6	0.1
Accretion of asset retirement obligations	2.2	2.2	-	2.0	2.0	-
Deferred income tax expense (benefit) (3)	(2.4)	0.7	(3.1)	0.7	0.8	(0.1)
Equity earnings, net of distributions	-	-	-	(4.5)	(4.5)	-
Risk management activities (4)	(0.7)	(0.7)	-	-	(0.1)	0.1
(Gain) loss on sale or disposition of assets	(1.2)	(1.2)	-	3.8	3.8	-
(Gain) loss on debt redemptions and amendments	-	-	-	7.4	7.4	-
Changes in operating assets and liabilities (5)	36.6	26.7	9.9	(28.6)	(32.3)	3.7
Net cash provided by (used in) operating activities	424.5	456.8	(32.3)	181.6	195.7	(14.1)
Cash flows from investing activities						
Outlays for property, plant and equipment	(419.6)	(419.6)	-	(463.4)	(463.4)	-
Return of capital from unconsolidated affiliate	3.6	3.6	-	-	-	-
Other, net	2.3	2.3	-	(10.5)	(10.5)	-
Net cash used in investing activities	(413.7)	(413.7)	-	(473.9)	(473.9)	-
Cash flows from financing activities						
Loan Facilities - Partnership:						
Borrowings	950.0	950.0	-	1,305.0	1,305.0	-
Repayments	(850.0)	(850.0)	-	(1,181.4)	(1,181.4)	-
Accounts receivable securitization facility - Partnership						
Borrowings	67.8	67.8	-	207.7	207.7	-
Repayments	(113.2)	(113.2)	-	(82.4)	(82.4)	-
Loan Facilities - Non-Partnership:						
Borrowings (1)	39.0	-	39.0	30.0	-	30.0
Repayments (1)	(36.0)	-	(36.0)	(34.0)	-	(34.0)
Costs incurred in connection with financing arrangements	(1.7)	(1.7)	-	(11.7)	(11.7)	-
Proceeds from sale of common units of the Partnership, net (6)	164.7	168.1	(3.4)	231.2	235.2	(4.0)
Distributions to owners (7)	(168.7)	(254.3)	85.6	(125.9)	(189.5)	63.6
Dividends to common and common equivalent shareholders	(52.7)	-	(52.7)	(39.6)	-	(39.6)
Repurchase of common stock	(0.8)	-	(0.8)	-	-	-

Net cash provided by (used in) financing activities	(1.6)	(33.3)	31.7	298.9	282.9	16.0
Net change in cash and cash equivalents	9.2	9.8	(0.6)	6.6	4.7	1.9
Cash and cash equivalents, beginning of period	66.7	57.5	9.2	76.3	68.0	8.3
Cash and cash equivalents, end of period	$75.9	$ 67.3	$ 8.6	$82.9	$72.7	$ 10.2

The major Non-Partnership cash flow items relate to:

(1) Cash and non-cash activity related to TRC debt obligations.
(2) Compensation on TRC's equity grants.
(3) TRC's federal and state income taxes.
(4) Non-cash OCI hedge realizations related to predecessor operations.
(5) See Balance Sheet – Partnership versus Non-Partnership for a description of the Non-Partnership operating assets and liabilities.
(6) Contributions to the Partnership to maintain 2% General Partner ownership.
(7) Distributions received by TRC from the Partnership for its general partner interest, limited partner interest and IDRs.

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Consolidated Results of Operations

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	($ in millions, except operating statistics)							
Revenues	$2,061.9	$1,441.6	$620.3	43 %	$4,414.8	$2,839.4	$1,575.4	55 %
Product purchases	1,677.9	1,176.4	501.5	43 %	3,651.2	2,313.9	1,337.3	58 %
Gross margin (1)	384.0	265.2	118.8	45 %	763.6	525.5	238.1	45 %
Operating expenses	106.6	96.1	10.5	11 %	210.9	182.2	28.7	16 %
Operating margin (2)	277.4	169.1	108.3	64 %	552.7	343.3	209.4	61 %
Depreciation and amortization expenses	85.9	65.7	20.2	31 %	165.4	129.7	35.7	28 %
General and administrative expenses	41.6	38.4	3.2	8 %	79.5	74.6	4.9	7 %
Other operating (income) expense	(0.4)	4.1	(4.5)	110%	(1.0)	4.2	(5.2)	124%
Income from operations	150.3	60.9	89.4	147%	308.8	134.8	174.0	129%
Interest expense, net	(35.7)	(32.4)	(3.3)	10 %	(69.6)	(64.5)	(5.1)	8 %
Equity earnings	4.2	2.9	1.3	45 %	9.1	4.5	4.6	102%
Gain (loss) on debt redemptions and amendments	-	(7.4)	7.4	100%	-	(7.4)	7.4	100%
Other (income) expense	(0.1)	6.5	(6.6)	102%	-	6.3	(6.3)	100%
Income tax (expense) benefit	(15.5)	(8.0)	(7.5)	94 %	(38.1)	(17.5)	(20.6)	118%
Net income	103.2	22.5	80.7	359%	210.2	56.2	154.0	274%
Less: Net income attributable to noncontrolling interests	76.8	7.5	69.3	924 %	164.2	27.9	136.3	489 %
Net income available to common shareholders	$26.4	$15.0	$11.4	76 %	$46.0	$28.3	$17.7	63 %
Operating statistics:								
Crude oil gathered, MBbl/d	83.8	38.3	45.5	119%	79.3	34.9	44.4	127%
Plant natural gas inlet, MMcf/d (3) (4)	2,113.8	2,072.2	41.6	2 %	2,081.2	2,075.6	5.6	0 %
Gross NGL production, MBbl/d	155.9	131.2	24.7	19 %	149.4	132.3	17.1	13 %
Export volumes, MBbl/d (5)	159.0	41.2	117.8	286%	137.4	43.0	94.4	220%
Natural gas sales, BBtu/d (4)	879.8	953.1	(73.3)	8 %	873.6	901.7	(28.1)	3 %
NGL sales, MBbl/d	397.6	282.7	114.9	41 %	399.3	282.0	117.3	42 %
Condensate sales, MBbl/d	5.0	4.0	1.0	25 %	4.3	3.7	0.6	16 %

(1) Gross margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate the Partnership’s Operations”.

(2) Operating margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate the Partnership’s Operations”.

(3) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.

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

(5) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine terminal that are destined for international markets.

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Revenues, including the impact of hedging, increased due to higher commodity volumes ($320.2 million), higher natural gas and NGL commodity sales prices ($174.4 million) and higher fee-based and other revenues ($125.7 million).

Higher consolidated gross margin in 2014 was primarily driven by increased export activities and higher fractionation fees in the Partnership's Logistics and Marketing segments and increased throughput volumes associated with system expansions and higher commodity sales prices in the Partnership's Field Gathering and Processing segment. This significant growth in the Partnership's asset base brought a higher level of operating expenses in 2014. See "—Results of Operations of the Partnership—By Reportable Segment" for additional information regarding changes in the components of gross margin and operating margin on a disaggregated basis.

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The increase in depreciation and amortization expenses reflects increased amortization of the Badlands intangible assets and higher depreciation related to the timing of major organic investments placed in service during the last twelve months, including CBF Train 4, Phase I of the international export expansion project, portions of Phase II of the international export expansion project, the Longhorn and High Plains plants and other system expansions.

Higher general and administrative expenses reflect increased compensation related costs to support the Partnership's expanding business operations.

The decrease in other operating expense primarily relates to losses on asset disposals recorded in 2013, compared to a gain on asset disposals recorded in 2014.

The increase in interest expense was primarily driven by lower capitalized interest allocated to our major expansion projects and higher outstanding borrowings partially offset by lower overall interest rates.

Higher equity earnings in the Partnership's investment in GCF was attributable to higher system product gains at the facility in 2014.

Losses on debt redemptions and amendments during 2013 were attributable to premiums paid and write-offs of debt issue costs in connection with the redemption of the 6 % Notes.

The other income in 2013 was attributable to the reduction of the contingent consideration liability associated with the Badlands acquisition.

Net income attributable to noncontrolling interests increased as our joint ventures experienced higher earnings in 2014.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Revenues, including the impact of hedging, increased due to higher commodity volumes ($723.3 million), higher natural gas and NGL commodity sales prices ($632.5 million) and higher fee-based and other revenues ($219.6 million). The other changes in the Partnership's results of operations for the six months were primarily driven by the same factors as the three month factors noted above.

The increase in net income attributable to noncontrolling interests is primarily due to higher Partnership earnings.

Results of Operations—By Reportable Segment

We have segregated the following segment operating margins between Partnership and TRC Non-Partnership activities.

	Partnership						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	TRC Non-Partnership	Consolidated Operating Margin
	(In millions)						
Three Months Ended:							
June 30, 2014	$97.7	$ 21.8	$ 108.6	$ 53.3	$(4.0)	$ -	$ 277.4
June 30, 2013	67.3	16.7	52.1	27.4	5.6	-	169.1

Six Months Ended:							
June 30, 2014	$191.7	$ 47.8	$ 205.4	$ 117.9	$(10.1)	$ -	$ 552.7
June 30, 2013	121.1	40.1	108.6	61.4	12.3	(0.2)	343.3

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Results of Operations of the Partnership – By Reportable Segment

Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)							
Gross margin	$144.1	$110.2	$33.9	31 %	$282.9	$201.7	$81.2	40 %
Operating expenses	46.4	42.9	3.5	8 %	91.2	80.6	10.6	13 %
Operating margin	$97.7	$67.3	$30.4	45 %	$191.7	$121.1	$70.6	58 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Sand Hills	159.8	162.4	(2.6)	2 %	163.2	157.4	5.8	4 %
SAOU (4)	177.0	155.1	21.9	14 %	171.5	147.2	24.3	17 %
North Texas System (5)	357.6	290.8	66.8	23 %	344.5	275.9	68.6	25 %
Versado	170.2	170.8	(0.6)	0 %	162.6	165.8	(3.2)	2 %
Badlands (6)	38.1	20.4	17.7	87 %	36.3	18.4	17.9	97 %
	902.7	799.5	103.2	13 %	878.1	764.7	113.4	15 %
Gross NGL production, MBbl/d (3)								
Sand Hills	18.4	17.5	0.9	5 %	18.3	17.5	0.8	5 %
SAOU	25.2	22.7	2.5	11 %	24.7	21.7	3.0	14 %
North Texas System	37.6	32.0	5.6	18 %	35.5	30.5	5.0	16 %
Versado	21.5	20.6	0.9	4 %	20.2	20.0	0.2	1 %
Badlands	3.3	1.8	1.5	83 %	3.2	1.7	1.5	88 %
	106.0	94.6	11.4	12 %	101.9	91.4	10.5	11 %
Crude oil gathered, MBbl/d	83.8	38.3	45.5	119%	79.3	34.9	44.4	127%
Natural gas sales, BBtu/d (3)	454.7	379.1	75.6	20 %	440.6	359.3	81.3	23 %
NGL sales, MBbl/d	80.5	67.3	13.2	20 %	78.0	69.0	9.0	13 %
Condensate sales, MBbl/d	4.1	3.6	0.5	14 %	3.5	3.3	0.2	6 %
Average realized prices (7):								
Natural gas, $/MMBtu	4.24	3.89	0.35	9 %	4.43	3.53	0.90	25 %
NGL, $/gal	0.77	0.69	0.08	12 %	0.81	0.71	0.10	14 %
Condensate, $/Bbl	90.36	90.58	(0.22)	0 %	89.92	88.40	1.52	2 %

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

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

(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

(4) Includes volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.

(5)

Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.

(6) Badlands natural gas inlet represents the total wellhead gathered volume.

(7) Average realized prices exclude the impact of hedging settlements presented in Other.

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Gross margin improvements in our Field Gathering and Processing segment were fueled by expansion-driven and producer activity-driven throughput increases and higher natural gas and NGL sales prices. The increase in plant inlet volumes was driven by system expansions and by increased producer activity which increased available supply across our areas of operation. The second quarter of 2014 also benefited from the start-up of commercial operations in May at the Longhorn Plant in North Texas and in June at the High Plains Plant in SAOU. Despite operational issues which reduced Sand Hills and Versado plant inlet volumes, NGL production at those operations increased due to higher average GPM gas supply. Badlands crude oil and natural gas volumes increased significantly as a result of our continuing investment to expand and improve gathering and processing capabilities. Higher NGL sales reflect both our expanding operations, as well as the impact of the CBF planned curtailment during the second quarter of 2013 which resulted in a temporary build of y-grade inventory.

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Higher operating expenses were driven by volume growth and system expansions and included additional labor costs, ad valorem taxes and compression and system maintenance expenses.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The six month results were impacted by the same factors as discussed above for the three month comparison of 2014 to 2013 with the addition of higher condensate sales prices and the impact of the severe cold weather in the first quarter of 2014 which constrained throughput volumes and increased operating expenses.

Coastal Gathering and Processing

	Three Months Ended June 30,				Six Months Ended June 30,			
			2014 vs.				2014 vs.	
	2014	2013	2013		2014	2013	2013	
	($ in millions, except operating statistics and price amounts)							
Gross margin	$33.4	$28.6	$4.8	17 %	$69.8	$62.6	$7.2	12%
Operating expenses	11.6	11.9	(0.3)	3 %	22.0	22.5	(0.5)	2 %
Operating margin	$21.8	$16.7	$5.1	31 %	$47.8	$40.1	$7.7	19%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
LOU	307.5	317.7	(10.2)	3 %	316.2	329.5	(13.3)	4 %
VESCO	519.9	493.3	26.6	5 %	505.3	513.6	(8.3)	2 %
Other Coastal Straddles	383.7	468.0	(84.3)	18 %	381.6	471.3	(89.7)	19%
	1,211.1	1,279.0	(67.9)	5 %	1,203.1	1,314.4	(111.3)	8 %
Gross NGL production, MBbl/d (3)								
LOU	9.7	8.4	1.3	15 %	9.8	8.7	1.1	13%
VESCO	28.4	15.2	13.2	87 %	25.8	19.0	6.8	36%
Other Coastal Straddles	11.8	13.1	(1.3)	10 %	11.8	13.3	(1.5)	11%
	49.9	36.7	13.2	36 %	47.4	41.0	6.4	16%
Natural gas sales, BBtu/d (3)	259.3	285.3	(26.0)	9 %	273.4	280.2	(6.8)	2 %
NGL sales, MBbl/d	43.1	35.3	7.8	22 %	41.8	38.3	3.5	9 %
Condensate sales, MBbl/d	0.7	0.3	0.4	133%	0.6	0.4	0.2	50%
Average realized prices:								
Natural gas, $/MMBtu	4.65	4.09	0.56	14 %	4.84	3.78	1.06	28%
NGL, $/gal	0.83	0.81	0.02	2 %	0.88	0.83	0.05	6 %
Condensate, $/Bbl	98.57	102.63	(4.06)	4 %	98.32	107.19	(8.87)	8 %

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

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

(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Higher Coastal Gathering and Processing gross margin was primarily driven by new higher GPM volumes at VESCO and LOU. The decrease in plant inlet volumes at LOU and Coastal Straddles was largely attributable to the decline in leaner other off-system supply volumes. Gross NGL production at VESCO during the second quarter of 2013 was impacted by a NGL takeaway pipeline volume constraint.

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Operating expenses were relatively flat.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The increase in Coastal Gathering and Processing gross margin was primarily due to new higher GPM volumes at VESCO and LOU, the short-term availability of higher GPM off-system volumes at LOU and higher NGL sales prices. The decrease in plant inlet volumes was largely attributable to the decline in leaner other off-system supply volumes. Gross NGL production at VESCO during the first six months of 2013 was impacted by a NGL takeaway pipeline volume constraint.

Operating expenses were relatively flat.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	($ in millions, except operating statistics)							
Gross margin	$148.0	$84.7	$63.3	75 %	$284.6	$171.3	$113.3	66%
Operating expenses	39.4	32.6	6.8	21 %	79.2	62.7	16.5	26%
Operating margin	$108.6	$52.1	$56.5	108%	$205.4	$108.6	$96.8	89%
Operating statistics MBbl/d(1):								
Fractionation volumes	346.3	256.6	89.7	35 %	329.5	257.3	72.2	28%
LSNG treating volumes	23.2	19.4	3.8	20 %	23.8	22.6	1.2	5 %
Benzene treating volumes	23.2	16.9	6.3	37 %	23.8	18.8	5.0	27%

(1) For all volume statistics presented, the numerator is the total volume during the applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Logistics Assets gross margin was significantly higher due to increased LPG export activity and increased fractionation activities, despite the continued impact of third-party ethane rejection. The second quarter of 2014 also included higher fractionation reservation fees. LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 159.0 MBbl/d in the second quarter of 2014 compared to 41.2 MBbl/d for the same period last year. This increase was driven by the first phase of our international export expansion project, which was placed into service September 2013, and by our second phase expansion project which added incremental capacity and operational efficiency in the second quarter of 2014. The second phase is expected to be fully operational in the third quarter of 2014. Higher 2014 fractionation volumes were due to CBF Train 4 which commenced commercial operations during the third quarter of 2013. In addition, CBF fractionation volumes during the second quarter of 2013 were partially curtailed by a planned maintenance turnaround. Higher 2014 gross margins also include the impact of higher fuel prices which pass through to operating expenses.

Higher operating expenses reflect the expansion of our export and fractionation facilities described above and increased power and fuel costs (which have a corresponding impact on higher fractionating and treating fee revenues). Partially offsetting these factors were higher system product gains in 2014.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The six month results were impacted by the same factors as discussed above for the three month comparison of 2014 to 2013. LPG export volumes averaged 137.4 MBbl/d for the six months ended June 2014 compared to 43.0 MBbl/d for the same six month period of 2013. In addition, the six months ended June 2014 also included higher reservation fees for both fractionation and LPG export activities.

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Marketing and Distribution

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)							
Gross margin	$65.7	$37.2	$28.5	77%	$143.4	$82.0	$61.4	75%
Operating expenses	12.4	9.8	2.6	27%	25.5	20.6	4.9	24%
Operating margin	$53.3	$27.4	$25.9	95%	$117.9	$61.4	$56.5	92%
Operating statistics (1):								
NGL sales, MBbl/d	403.0	282.9	120.1	42%	403.7	283.3	120.4	42%
Average realized prices:								
NGL realized price, $/gal	0.92	0.84	0.08	10%	1.03	0.88	0.15	17%

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

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Marketing and Distribution gross margin increased primarily due to higher LPG export activity (which benefits both the Logistics Assets and Marketing and Distribution segments) and higher NGL marketing activities.

Operating expenses increased primarily due to increased barge and terminal maintenance, partially offset by lower truck utilization.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

The six month results were impacted by the same factors as discussed above for the three month comparison of 2014 to 2013.

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	2014 vs. 2013	2014	2013	2014 vs. 2013
	($ in millions)					
Gross margin	$(4.0)	$5.6	$(9.6)	$(10.1)	$12.3	$(22.4)
Operating margin	$(4.0)	$5.6	$(9.6)	$(10.1)	$12.3	$(22.4)

Other contains the financial effects of the Partnership's hedging program on operating margin as it represents the cash settlements on its derivative contracts. The primary purpose of the commodity risk management activities is to mitigate a portion of the impact of commodity prices on the Partnership's operating cash flow. The Partnership has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from their percent of proceeds or liquids processing arrangements by entering into derivative instruments. Because the Partnership is essentially forward-selling a portion of its plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

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The following table provides a breakdown of the change in Other operating margin:

	Three Months Ended June 30, 2014			Three Months Ended June 30, 2013			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread	Gain (Loss)	Volume Settled	Price Spread	Gain (Loss)	2014 vs. 2013
Natural Gas (MMBtu)	5.3	$(0.46)	$(2.4)	2.4	$0.61	$1.5	$(3.9)
NGL (MMBbl)	4.3	0.12	0.5	21.6	0.21	4.6	(4.1)
Crude Oil (MMBbl)	0.2	(11.12)	(2.5)	0.2	(0.89)	(0.1)	(2.4)
Non-Hedge Accounting (1)			0.2			(0.3)	0.5
Ineffectiveness (2)			0.2			(0.1)	0.3
			$(4.0)			$5.6	$(9.6)

	Six Months Ended June 30, 2014			Six Months Ended June 30, 2013			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread	Gain (Loss)	Volume Settled	Price Spread	Gain (Loss)	2014 vs. 2013
Natural Gas (MMBtu)	9.8	$(0.70)	$(6.8)	4.7	$0.98	$4.7	$(11.5)
NGL (MMBbl)	8.6	0.02	0.1	43.0	0.19	8.1	(8.0)
Crude Oil (MMBbl)	0.4	(8.95)	(4.0)	0.3	(0.94)	(0.2)	(3.8)
Non-Hedge Accounting (1)			0.5			(0.2)	0.7
Ineffectiveness (2)			0.1			(0.1)	0.2
			$(10.1)			$12.3	$(22.4)

(1) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.

(2) Ineffectiveness primarily relates to certain crude hedging contracts.

Our Liquidity and Capital Resources

We have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common stockholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. See “Part II – Other Information, Item 1A. Risk Factors.” As of June 30, 2014, our interests in the Partnership consisted of the following:

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

- 12,945,659 of the 114,502,603 outstanding common units of the Partnership, representing an 11.3% limited partnership interest.

Our future cash flows will consist of distributions to us from our interests in the Partnership. These cash distributions to us should provide sufficient resources to fund our operations, long-term debt obligations and tax obligations for at least the next twelve months. Based on the anticipated levels of distributions from the Partnership that we expect to receive, we also expect that we will be able to fund the projected quarterly cash dividends to our stockholders for the next twelve months.

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

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As of June 30, 2014, our liquidity consisted of the following:

	June 30, 2014 (In millions)
Cash on hand	$ 8.6
Total availability under TRC's credit facility	150.0
Less: Outstanding borrowings under TRC's credit facility	(87.0)
Total liquidity	$ 71.6

We have sufficient liquidity to satisfy the $54.7 million tax liability we incurred as a result of our sales of assets to the Partnership over the next 11 years.

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

The following table details the dividends declared and/or paid by us during the three months ended June 30, 2014:

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, 2014	August 15, 2014	$ 29.2	$ 29.0	$ 0.2	$0.69000
March 31, 2014	May 16, 2014	27.4	27.2	0.2	0.64750
December 31, 2013	February 18, 2014	25.6	25.5	0.1	0.60750

(1) Represents accrued dividends on restricted stock and restricted stock units that are payable upon vesting.

The Partnership’s Liquidity and Capital Resources

The Partnership’s ability to finance its operations, including funding capital expenditures and acquisitions, meeting its indebtedness obligations, refinancing its indebtedness and meeting its collateral requirements, will depend on its ability to generate cash in the future. The Partnership’s ability to generate cash is subject to a number of factors, some of which are beyond its control. These include weather, commodity prices (particularly for natural gas and NGLs) and ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

The Partnership’s main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under the TRP Revolver, borrowings under the Securitization Facility, the issuance of additional common units and access to debt markets. The capital markets continue to experience volatility. The Partnership’s exposure to current credit conditions includes its credit facility, cash investments and counterparty performance risks. The Partnership continually monitors its liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

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As of June 30, 2014, the Partnership's liquidity consisted of the following:

	June 30, 2014 (In millions)
Cash on hand	$ 67.3
Total availability under the TRP Revolver	1,200.0
Total availability under the Securitization Facility	234.3
	1,501.6
Less: Outstanding borrowings under the TRP Revolver	(495.0)
Outstanding borrowings under the Securitization Facility	(234.3)
Outstanding letters of credit under the TRP Revolver	(94.6)
Total liquidity	$ 677.7

Other potential capital resources include:

- The Partnership's right to request an additional $300 million in commitment increases under the TRP Revolver.
- Approximately $385.4 million in remaining capacity as of July 21, 2014 in common units pursuant to the May 2014 EDA.
- The Partnership's ability to issue debt or equity securities pursuant to shelf registration statements, including availability under the Partnership's July 2013 Shelf and unlimited amounts under the Partnership's April 2013 Shelf.

A portion of the Partnership's capital resources may be allocated to letters of credit to satisfy certain counterparty credit requirements. While the Partnership's credit ratings have improved over time, these letters of credit reflect its non-investment grade status, as assigned to the Partnership by Moody's Investors Service, Inc. and S&P. They also reflect certain counterparties' views of its financial condition and ability to satisfy its performance obligations, as well as commodity prices and other factors.

Risk Management

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of the Partnership's cash flows, the Partnership has entered into derivative instruments to hedge the commodity price associated with a portion of its expected natural gas equity volumes through 2016 and our NGL and condensate equity volumes through 2014. See "Item 3. Quantitative and Qualitative Disclosures about Market Risk." The current market conditions may also impact the Partnership's ability to enter into future commodity derivative contracts.

The Partnership's risk management position has moved from a net liability position of $4.3 million at December 31, 2013 to a net liability position of $11.4 million at June 30, 2014. Aggregate forward prices for commodities are above the fixed prices the Partnership currently expects to receive on those derivative contracts, creating this net liability position. The Partnership accounts for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in other comprehensive income (“OCI”) until the underlying hedged transactions settle.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with receivables from NGL customers offset by plant settlements payable to producers. The factors that typically cause overall variability in the Partnership’s reported total working capital are: (1) the Partnership’s cash position; (2) liquids inventory levels and valuation, which the Partnership closely manages; (3) changes in the fair value of the current portion of derivative contracts; and (4) major structural changes in the Partnership’s asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

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The Partnership's working capital decreased $10.8 million, primarily attributable to higher plant settlements due to higher commodity volumes and higher gas prices. The effect of higher LPG export volumes was mitigated by lower quarter-end NGL prices. Other working capital factors included higher cash balances and lower affiliate payables related to the timing of the Partnership's reimbursements to us, offset by higher ad valorem taxes and increased liabilities from risk management activities.

The non-Partnership working capital increased $4.3 million for the six months ended June 30, 2014, primarily due to higher deferred tax assets, higher prepaid insurance, lower accrued liabilities partially offset by lower affiliate receivables.

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

Cash Flow

The following table and discussion summarize our Consolidated Cash Flows provided by or used in operating activities, investing activities and financing activities for the periods indicated. See "Statement of Cash Flows – Partnership versus Non-Partnership" for a detailed presentation of cash flow activity:

Six Months Ended June 30, 2014	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)		
Net cash provided by (used in):			
Operating activities	$424.5	$ 456.8	$ (32.3)
Investing activities	(413.7)	(413.7)	-
Financing activities	(1.6)	(33.3)	31.7
Six Months Ended June 30, 2013			
Net cash provided by (used in):			
Operating activities	$181.6	$ 195.7	$ (14.1)
Investing activities	(473.9)	(473.9)	-
Financing activities	298.9	282.9	16.0

Cash Flow from Operating Activities

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

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

	Six Months Ended June 30,					
	2014			2013		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership
	(In millions)					
Cash flows from operating activities:						
Cash received from customers	$4,440.1	$4,440.3	$ (0.2)	$2,900.4	$2,900.3	$ 0.1
Cash received from (paid to) derivative counterparties	(11.6)	(11.6)	-	12.3	12.3	-
Cash outlays for:						
Product purchases	3,670.3	3,670.3	-	2,421.8	2,421.8	-
Operating expenses	170.5	170.4	0.1	156.6	156.8	(0.2)
General and administrative expenses	73.8	76.7	(2.9)	80.0	87.7	(7.7)
Cash distributions from equity investment (1)	(9.1)	(9.1)	-	-	-	-
Interest paid, net of amounts capitalized (2)	62.7	61.4	1.3	55.9	54.6	1.3
Income taxes paid, net of refunds	35.8	2.0	33.8	23.1	2.3	20.8
Other cash (receipts) payments	-	0.2	(0.2)	(6.3)	(6.3)	-
Net cash provided by operating activities	$424.5	$456.8	$ (32.3)	$181.6	$195.7	$ (14.1)

(1) Excludes $3.6 million included in investing activities for the six months ended June 30, 2014.

(2) Net of capitalized interest paid of $11.5 million and $14.8 million included in investing activities for the six months ended June 30, 2014 and 2013.

Higher natural gas prices, sales and logistics fees related to export activities and higher other volumes contributed to increased cash collections in 2014 compared to 2013, as well as higher cash payments to producers for commodity products. The change in cash received related to derivatives reflects higher aggregate commodity prices paid to counterparties compared to the aggregate fixed price the Partnership received on those derivative contracts.

Cash Flow from Investing Activities - Partnership

The decrease in net cash used in investing activities was primarily due to lower cash outlays for current capital expansion projects of $42.0 million.

Cash Flow from Financing Activities - Partnership

The increase in net cash used in financing activities was primarily due to an increase in net repayments under the Securitization Facility ($170.7 million), an increase in distributions to owners ($50.7 million), and a decrease in proceeds from less equity offerings ($67.1 million).

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The Partnership's primary financing activities during the six months ended 2014 and 2013 are summarized in the following tables.

Six Months Ended June 30, 2014 (In millions)	Financing Activity	Source (Use)	Use of proceeds
Various	Net proceeds under TRP Revolver	$100.0	For general Partnership purposes
Various	Net repayments under the Securitization Facility	(45.4)	
Various	Distributions	(237.1)	
Various	Sale of common units - 2013 EDA	164.7	Reduce outstanding borrowings under the
Various	General partner contributions to maintain 2% interest	3.4	TRP Revolver and for general Partnership purposes

Six Months Ended June 30, 2013 (In millions)	Financing Activity	Source (Use)	Use of proceeds
May	Issuance of the 4¼% Notes in May 2013	$618.1	Redeem borrowings under 11¼% Notes; reduce outstanding borrowings under TRP Revolver and for general Partnership purposes
June	Redemption of $100.0 million - 6 % Notes	(106.4)	
Various	Net repayments under TRP Revolver	(395.0)	
Various	Distributions	(186.4)	
Various	Sale of common units - 2012 and 2013 EDAs	231.2	Redeem borrowings under 6 % Notes, reduce outstanding borrowings under TRP Revolver and general Partnership purposes
Various	General partner contributions to maintain 2% interest	4.0	Reduce outstanding borrowings under the
Various	Net borrowings under the Securitization Facility	125.3	TRP Revolver and for general Partnership purposes

Cash Flow Financing Activities - Non-Partnership

Financing activities provided a net source of cash compared to a use in six months ended June 30, 2014 primarily due to an increase in distributions received of $22.0 million, and an increase in net borrowings under the TRC Revolver of $7.0 million partially offset by an increase in dividends paid of $13.1 million.

Distributions from the Partnership and Dividends of TRC

The following table details the distributions declared and/or paid by the Partnership for six months ended June 30, 2014 with respect to our 2% general partner interest, the associated IDRs and common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods:

For the Three Months Ended	Date Paid or to be Paid	Cash Distribution Per Limited Partner Unit	Cash Distributions Limited Partner Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (1)	Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
		(In millions, except per unit amounts)						
June 30, 2014	August 14, 2014	$0.7800	$10.1	$ 2.5	$33.7	$ 46.3	$0.69000	$ 29.2
March 31, 2014	May 15, 2014	0.7625	9.9	2.4	31.7	44.0	0.64750	27.4
December 31, 2013	February 14, 2014	0.7475	9.7	2.3	29.5	41.5	0.60750	25.6

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

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Capital Requirements

The Partnership's capital requirements relate to capital expenditures, which are classified as expansion expenditures, maintenance expenditures or business acquisitions. Expansion capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues, and fund acquisitions of businesses or assets. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of the Partnership's existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life, and expenditures to remain in compliance with environmental laws and regulations. Non-Partnership currently does not have any capital expenditures.

	Six Months Ended June 30,	
	2014	2013
Capital expenditures :	(In millions)	
Expansion	$357.2	$399.2
Maintenance	33.7	43.4
Gross additions	390.9	442.6
Transfers from materials and supplies inventory to property, plant and equipment	(1.4)	-
Decrease in capital project payables and accruals	30.1	20.8
Cash outlays for capital projects	$419.6	$463.4

The Partnership estimates that its total growth capital expenditures for 2014 will be approximately $780 million on a gross basis, and maintenance capital expenditures net to its interest will be approximately $90 million. Given the Partnership's objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, it anticipates that over time that it will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. The Partnership expects to fund future capital expenditures with funds generated from its operations, borrowings under the TRP Revolver and the Securitization Facility and proceeds from issuances of additional equity and debt securities.

Critical Accounting Policies and Estimates

The Partnership and our critical accounting policies and estimates are set forth in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report.

Off-Balance Sheet Arrangements

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2013, in Item 7A in our 2013 Annual Report on Form 10-K. The Partnership added 18,000 MMBtu/d of natural gas hedges for 2014 and 16,000 MMBtu/d of natural gas hedges for 2015 during the six months ended June 30, 2014. For more information on risk management activities, see Note 13 "Derivative Instruments and Hedging Activities" to our consolidated financial statements included elsewhere in this Quarterly Report.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2014, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this Quarterly Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

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Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended June 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 15 – Commitments and Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see “Item 1A. Risk Factors.” in our Annual Report. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

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Item 6. Exhibits.

Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.2 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.3	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.4	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.5	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.6	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.7	Amendment No. 2, dated May 25, 2012, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 25, 2012 (File No. 001-33303)).
3.8	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.9	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.10	Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.9 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 28, 2011 (File No. 001-34991)).
3.11	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
** Furnished herewith

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	Targa Resources Corp. (Registrant)
Date: August 1, 2014	By: /s/ Matthew J. Meloy Matthew J. Meloy Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)