

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

FORM 10-Q

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

For the quarterly period ended September 30, 2013

or

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

For the transition period from _____ to _____

Commission File Number: 001-34991



TARGA RESOURCES CORP.

(Exact name of registrant as specified in its charter)

Delaware

(State or other jurisdiction of incorporation or organization)

20-3701075

(I.R.S. Employer Identification No.)

1000 Louisiana St, Suite 4300, Houston, Texas

(Address of principal executive offices)

77002

(Zip Code)

(713) 584-1000

(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer

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

As of October 28, 2013, there were 42,331,487 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," "potential," "plan," "forecast" and other similar words.

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

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

- 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 of 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." of this Quarterly Report, our Annual Report on Form 10-K for the year ended December 31, 2012 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in “Part II-Other Information, Item 1A. Risk Factors.” in this Quarterly Report and in our Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

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

Bbl	Barrels (equal to 42 U.S. gallons)
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
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

PART I – FINANCIAL INFORMATION
Item 1. Financial Statements.
**TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS**

	September 30, 2013	December 31, 2012
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 83.7	\$ 76.3
Trade receivables, net of allowances of \$0.9 million and \$0.9 million	498.5	514.9
Inventories	201.7	99.4
Assets from risk management activities	10.9	29.3
Other current assets	14.2	13.4
Total current assets	<u>809.0</u>	<u>733.3</u>
Property, plant and equipment	5,454.0	4,708.0
Accumulated depreciation	<u>(1,344.6)</u>	<u>(1,170.0)</u>
Property, plant and equipment, net	4,109.4	3,538.0
Other intangible assets, net	660.3	680.8
Long-term assets from risk management activities	3.9	5.1
Investment in unconsolidated affiliate	51.2	53.1
Other long-term assets	91.5	94.7
Total assets	<u>\$ 5,725.3</u>	<u>\$ 5,105.0</u>
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 679.6	\$ 679.0
Deferred income taxes	2.0	0.2
Liabilities from risk management activities	5.5	7.4
Total current liabilities	<u>687.1</u>	<u>686.6</u>
Long-term debt	2,867.9	2,475.3
Long-term liabilities from risk management activities	1.6	4.8
Deferred income taxes	136.1	131.2
Other long-term liabilities	58.0	53.7
Commitments and contingencies (see Note 14)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock (\$0.001 par value, 300,000,000 shares authorized, 42,529,218 shares issued and 42,331,487 shares outstanding as of September 30, 2013, and 42,492,233 shares issued and 42,294,502 shares outstanding as of December 31, 2012)	-	-
Preferred stock (\$0.001 par value, 100,000,000 shares authorized, no shares issued and outstanding as of September 30, 2013 and December 31, 2012)	-	-
Additional paid-in capital	147.6	184.4
Retained earnings (accumulated deficit)	12.6	(32.0)
Accumulated other comprehensive income	0.3	1.2
Treasury stock, at cost (197,731 shares as of September 30, 2013 and as of December 31, 2012)	<u>(9.5)</u>	<u>(9.5)</u>
Total Targa Resources Corp. stockholders' equity	151.0	144.1
Noncontrolling interests in subsidiaries	<u>1,823.6</u>	<u>1,609.3</u>
Total owners' equity	1,974.6	1,753.4
Total liabilities and owners' equity	<u>\$ 5,725.3</u>	<u>\$ 5,105.0</u>

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2013	2012	2013	2012
	(Unaudited)			
	(In millions, except per share amounts)			
Revenues	\$ 1,556.8	\$ 1,393.5	\$ 4,396.2	\$ 4,358.4
Costs and expenses:				
Product purchases	1,259.8	1,153.0	3,573.8	3,611.8
Operating expenses	97.6	78.3	279.8	227.2
Depreciation and amortization expenses	69.0	48.6	198.7	144.3
General and administrative expenses	37.7	35.7	112.5	106.5
Other operating expense	4.2	18.9	8.3	18.8
Income from operations	88.5	59.0	223.1	249.8
Other income (expense):				
Interest expense, net	(33.4)	(30.0)	(97.9)	(91.0)
Equity earnings (loss)	5.6	(2.2)	10.1	(0.3)
Loss on debt redemption	(7.4)	-	(14.7)	-
Other	9.1	(1.8)	15.3	(2.1)
Income before income taxes	62.4	25.0	135.9	156.4
Income tax expense:				
Current	(6.6)	(4.3)	(23.3)	(20.3)
Deferred	(6.4)	(1.7)	(7.0)	(4.4)
	(13.0)	(6.0)	(30.3)	(24.7)
Net income	49.4	19.0	105.6	131.7
Less: Net income attributable to noncontrolling interests	33.1	10.3	61.0	104.8
Net income available to common shareholders	\$ 16.3	\$ 8.7	\$ 44.6	\$ 26.9
Net income available per common share - basic	\$ 0.39	\$ 0.21	\$ 1.07	\$ 0.66
Net income available per common share - diluted	\$ 0.39	\$ 0.21	\$ 1.06	\$ 0.64
Weighted average shares outstanding - basic	41.6	41.0	41.6	41.0
Weighted average shares outstanding - diluted	42.1	41.9	42.1	41.8

See notes to consolidated financial statements.

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

Three Months Ended September 30,

	2013			2012		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income attributable to Targa Resources Corp.			\$ 16.3			\$ 8.7
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	\$ (1.6)	\$ 0.6	(1.0)	\$ (3.7)	\$ 2.0	(1.7)
Settlements reclassified to revenues	(0.6)	0.2	(0.4)	(3.0)	1.6	(1.4)
Interest rate swaps:						
Settlements reclassified to interest expense, net	0.2	(0.1)	0.1	0.3	(1.0)	(0.7)
Other comprehensive income (loss) attributable to Targa Resources Corp.	\$ (2.0)	\$ 0.7	(1.3)	\$ (6.4)	\$ 2.6	(3.8)
Comprehensive income (loss) attributable to Targa Resources Corp.			<u>\$ 15.0</u>			<u>\$ 4.9</u>
Net income attributable to noncontrolling interests			\$ 33.1			\$ 10.3
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	\$ (9.7)	\$ -	(9.7)	\$ (18.9)	\$ (0.2)	(19.1)
Settlements reclassified to revenues	(3.9)	-	(3.9)	(12.4)	(0.1)	(12.5)
Interest rate swaps:						
Settlements reclassified to interest expense, net	1.3	-	1.3	1.6	-	1.6
Other comprehensive income (loss) attributable to noncontrolling interests	\$ (12.3)	\$ -	(12.3)	\$ (29.7)	\$ (0.3)	(30.0)
Comprehensive income (loss) attributable to noncontrolling interests			<u>\$ 20.8</u>			<u>\$ (19.7)</u>
Total comprehensive income (loss)			<u>\$ 35.8</u>			<u>\$ (14.8)</u>

See notes to consolidated financial statements.

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

Nine Months Ended September 30,

	2013			2012		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income attributable to Targa Resources Corp.			\$ 44.6			\$ 26.9
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	\$ 0.3	\$ (0.1)	0.2	\$ 11.5	\$ (2.5)	9.0
Settlements reclassified to revenues	(2.3)	0.9	(1.4)	(6.6)	1.4	(5.2)
Interest rate swaps:						
Settlements reclassified to interest expense, net	0.6	(0.3)	0.3	1.0	(1.3)	(0.3)
Other comprehensive income (loss) attributable to Targa Resources Corp.	\$ (1.4)	\$ 0.5	(0.9)	\$ 5.9	\$ (2.4)	3.5
Comprehensive income attributable to Targa Resources Corp.			<u>\$ 43.7</u>			<u>\$ 30.4</u>
Net income attributable to noncontrolling interests			\$ 61.0			\$ 104.8
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	\$ 2.1	\$ -	2.1	\$ 59.4	\$ -	59.4
Settlements reclassified to revenues	(14.7)	-	(14.7)	(25.1)	-	(25.1)
Interest rate swaps:						
Settlements reclassified to interest expense, net	4.1	-	4.1	5.1	-	5.1
Other comprehensive income (loss) attributable to noncontrolling interests	\$ (8.5)	\$ -	(8.5)	\$ 39.4	\$ -	39.4
Comprehensive income attributable to noncontrolling interests			<u>\$ 52.5</u>			<u>\$ 144.2</u>
Total comprehensive income			<u>\$ 96.2</u>			<u>\$ 174.6</u>

See notes to consolidated financial statements.

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

	Common Stock		Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares		Noncontrolling Interests	Total	
	Shares	Amount				Shares	Amount			
(Unaudited)										
(In millions, except shares in thousands)										
Balance, December 31, 2012	42,295	\$ -	\$ 184.4	\$ (32.0)	\$ 1.2	198	\$ (9.5)	\$ 1,609.3	\$ 1,753.4	
Compensation on equity grants	36	-	5.6	-	-	-	-	4.4	10.0	
Accrual of distribution equivalent rights	-	-	-	-	-	-	-	(1.1)	(1.1)	
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	377.4	377.4	
Receivables from unit offerings	-	-	(3.3)	-	-	-	-	-	(3.3)	
Impact of Partnership equity transactions	-	-	23.8	-	-	-	-	(23.8)	-	
Dividends	-	-	(62.9)	-	-	-	-	-	(62.9)	
Distributions	-	-	-	-	-	-	-	(195.1)	(195.1)	
Other comprehensive income (loss)	-	-	-	-	(0.9)	-	-	(8.5)	(9.4)	
Net income	-	-	-	44.6	-	-	-	61.0	105.6	
Balance, September 30, 2013	42,331	\$ -	\$ 147.6	\$ 12.6	\$ 0.3	198	\$ (9.5)	\$ 1,823.6	\$ 1,974.6	
Balance, December 31, 2011	42,398	\$ -	\$ 229.5	\$ (70.1)	\$ (1.3)	-	\$ -	\$ 1,172.6	\$ 1,330.7	
Compensation on equity grants	94	-	10.5	-	-	-	-	2.5	13.0	
Accrual of distribution equivalent rights	-	-	-	-	-	-	-	(0.4)	(0.4)	
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	115.2	115.2	
Impact of Partnership equity transactions	-	-	(20.3)	-	-	-	-	20.3	-	
Dividends	-	-	(46.5)	-	-	-	-	-	(46.5)	
Distributions	-	-	(1.2)	-	-	-	-	(158.1)	(159.3)	
Other comprehensive income (loss)	-	-	-	-	3.5	-	-	39.4	42.9	
Net income	-	-	-	26.9	-	-	-	104.8	131.7	
Balance, September 30, 2012	42,492	\$ -	\$ 172.0	\$ (43.2)	\$ 2.2	-	\$ -	\$ 1,296.3	\$ 1,427.3	

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2013	2012
	(Unaudited)	
	(In millions)	
Cash flows from operating activities		
Net income	\$ 105.6	\$ 131.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Amortization in interest expense	12.1	14.7
Compensation on equity grants	10.0	13.0
Depreciation and amortization expense	198.7	144.3
Accretion of asset retirement obligations	3.0	3.0
Deferred income tax expense	7.0	4.4
Equity (earnings) loss, net of distributions	-	0.3
Risk management activities	-	1.7
Loss (gain) on sale or disposition of assets	3.1	15.5
Loss on debt redemption	14.7	-
Changes in operating assets and liabilities:		
Receivables and other assets	19.7	162.9
Commodity Inventories	(110.3)	4.9
Accounts payable and other liabilities	(5.5)	(206.2)
Net cash provided by operating activities	<u>258.1</u>	<u>290.2</u>
Cash flows from investing activities		
Outlays for property, plant and equipment	(708.2)	(365.1)
Business acquisition, net of cash acquired	-	(25.8)
Purchase of materials and supplies	(35.3)	-
Investment in unconsolidated affiliate	-	(16.8)
Return of capital from unconsolidated affiliate	1.9	2.3
Other, net	4.0	1.6
Net cash used in investing activities	<u>(737.6)</u>	<u>(403.8)</u>
Cash flows from financing activities		
Partnership loan facilities:		
Borrowings	1,743.0	1,120.0
Repayments	(1,521.2)	(938.0)
Partnership accounts receivable securitization facility:		
Borrowings	261.6	-
Repayments	(93.6)	-
Non-Partnership loan facilities:		
Borrowings	36.0	-
Repayments	(48.0)	-
Costs incurred in connection with financing arrangements	(13.6)	(10.0)
Distributions	(195.1)	(159.3)
Equity offering of the Partnership units	379.6	120.7
Dividends to common shareholders	(61.8)	(44.9)
Net cash provided by financing activities	<u>486.9</u>	<u>88.5</u>
Net change in cash and cash equivalents	7.4	(25.1)
Cash and cash equivalents, beginning of period	76.3	145.8
Cash and cash equivalents, end of period	<u>\$ 83.7</u>	<u>\$ 120.7</u>

See notes to consolidated financial statements.

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

The year-end condensed balance sheet data was derived from audited financial statements, but does not include all disclosures required by GAAP.

Note 1 — Organization

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

Note 2 — Basis of Presentation

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

The unaudited consolidated financial statements for the three and nine months ended September 30, 2013 and 2012 include all adjustments, which we believe are necessary, for a fair presentation of the results for interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods may have been reclassified to conform to the current year presentation.

Our financial results for the three and nine months ended September 30, 2013 are not necessarily indicative of the results that may be expected for the full year.

Except as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

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

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

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all Incentive Distribution Rights (“IDRs”); and
- 12,945,659 common units of the Partnership, representing a 11.9% limited partnership interest.

The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; gathering, storing and terminaling crude oil; and storing, terminaling and selling refined petroleum products. See Note 16 for an analysis of our and the Partnership’s operations by segment.

Note 3 — Significant Accounting Policies

Accounting Policy Updates/Revisions

The accounting policies that we follow are set forth in Note 3 of the Notes to Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2012. Significant updates or revisions to these policies during the nine months ended September 30, 2013 are shown below.

Accounts Receivable Securitization Facility

Proceeds from the sale or contribution of certain receivables under our Accounts Receivable Securitization Facility (the “Securitization Facility”) are treated as collateralized borrowings in our financial statements. Such borrowings are reflected as long-term debt on our balance sheets to the extent that the Partnership has the ability and intent to fund the Securitization Facility’s borrowings on a long-term basis. Proceeds and repayments under the Securitization Facility are reflected as cash flows from financing activities on our statements of cash flows.

Intangible Assets

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

Recent Accounting Pronouncements

In January 2013, the FASB issued Accounting Standards Update No. 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*, which clarifies that ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*, applies to financial instruments or derivative transactions accounted for under ASC 815. We currently present the Partnership’s derivative assets and liabilities on a gross basis on our statement of financial position. The amendments require disclosure of both gross and net amounts of derivative assets and liabilities that are subject to master netting arrangements with counterparties. We have provided these additional disclosures regarding the gross and net amounts of derivative assets and liabilities in Note 12.

Note 4 –Business Acquisitions

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

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

Changes in the fair value of this accrued liability are included in earnings and reported as Other income (expense) in the Consolidated Statement of Operations. As of September 30, 2013, the contingent consideration was re-estimated to be \$0, resulting in an increase in Other income of \$9.1 million for third quarter 2013 and \$15.3 million year-to-date 2013. The elimination of the contingent liability reflects management’s updated assessment, with only nine months remaining on the contingency period, that we will not meet the stipulated volumetric thresholds.

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

	<u>Year Ended December 31, 2012</u>		<u>Three Months Ended</u>	<u>Nine Months Ended</u>
			<u>September 30, 2012</u>	<u>September 30, 2012</u>
	<u>As reported in</u>	<u>Pro forma</u>	<u>Pro forma</u>	<u>Pro forma</u>
	<u>10-K</u>			
	(In millions, except per share amounts)			
Revenues	\$ 5,885.7	\$ 5,909.9	\$ 1,401.3	\$ 4,374.0
Net income	159.3	129.5	12.1	105.9
Less: Net income attributable to noncontrolling interests	121.2	83.5	1.4	72.4
Net income attributable to Targa Resources Corp.	<u>\$ 38.1</u>	<u>\$ 46.0</u>	<u>\$ 10.7</u>	<u>\$ 33.5</u>
Net income per common share - Basic	\$ 0.93	\$ 1.12	\$ 0.26	\$ 0.82
Net income per common share - Diluted	\$ 0.91	\$ 1.10	\$ 0.26	\$ 0.80

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

- depreciation expense associated with the fair value adjustments to property, plant and equipment using the straight-line method over a useful life of 15-20 years. The pro forma information included in our 2012 Form 10-K utilized a 30 year useful life;
- amortization expense associated with the fair value adjustments to definite-lived intangibles in a manner that follows the expected pattern of services provided to customers, over a useful life of 20 years. The pro forma information included in our 2012 Form 10-K utilized a straight-line method over a 30 year life; and
- adjustment to pro forma revenues to report purchases and sales on a net, rather than gross, basis for certain Badlands natural gas processing agreements in which we are in substance an agent rather than a principal.

Note 5 — Inventories

The components of inventories consisted of the following:

	<u>September 30, 2013</u>	<u>December 31, 2012</u>
Commodities	\$ 163.3	\$ 82.3
Materials and supplies	38.4	17.1
	<u>\$ 201.7</u>	<u>\$ 99.4</u>

Note 6 — Property, Plant and Equipment and Intangible Assets

	September 30, 2013			December 31, 2012			Estimated Useful Lives (In Years)
	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	
Gathering systems	\$ 2,119.7	\$ -	\$ 2,119.7	\$ 1,975.3	\$ -	\$ 1,975.3	5 to 20
Processing and fractionation facilities	1,528.4	6.6	1,535.0	1,251.6	6.6	1,258.2	5 to 25
Terminaling and storage facilities	691.5	-	691.5	462.0	-	462.0	5 to 25
Transportation assets	292.6	-	292.6	292.5	-	292.5	10 to 25
Other property, plant and equipment	109.2	0.2	109.4	84.6	0.2	84.8	3 to 25
Land	88.7	-	88.7	87.1	-	87.1	-
Construction in progress	617.1	-	617.1	548.1	-	548.1	-
Property, plant and equipment	\$ 5,447.2	\$ 6.8	\$ 5,454.0	\$ 4,701.2	\$ 6.8	\$ 4,708.0	
Accumulated depreciation	(1,342.4)	(2.2)	(1,344.6)	(1,168.0)	(2.0)	(1,170.0)	
Property, plant and equipment, net	\$ 4,104.8	\$ 4.6	\$ 4,109.4	\$ 3,533.2	\$ 4.8	\$ 3,538.0	
Intangible assets	\$ 681.8	\$ -	\$ 681.8	\$ 681.9	\$ -	\$ 681.9	20
Accumulated amortization	(21.5)	-	(21.5)	(1.1)	-	(1.1)	
Intangible assets, net	\$ 660.3	\$ -	\$ 660.3	\$ 680.8	\$ -	\$ 680.8	

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

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

Note 7 — Accounts Payable and Accrued Liabilities

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

	September 30, 2013	December 31, 2012
Commodities	\$ 451.0	\$ 416.8
Other goods and services	135.0	154.4
Interest	42.3	39.5
Compensation and benefits	32.5	40.7
Other	18.8	27.6
	\$ 679.6	\$ 679.0

Note 8 — Debt Obligations

	<u>September 30, 2013</u>	<u>December 31, 2012</u>
Long-term debt:		
Non-Partnership obligations:		
TRC Senior secured revolving credit facility, variable rate, due October 2017 (1)	\$ 70.0	\$ 82.0
Obligations of the Partnership: (2)		
Senior secured revolving credit facility, variable rate, due October 2017 (3)	400.0	620.0
Senior unsecured notes, 11¼% fixed rate, due July 2017 (4)	-	72.7
Unamortized discount	-	(2.5)
Senior unsecured notes, 7⅞% fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(28.7)	(30.5)
Senior unsecured notes, 6¾% fixed rate, due August 2022	300.0	400.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0	-
Accounts receivable securitization facility, due January 2014 (5)	168.0	-
Total long-term debt	<u>\$ 2,867.9</u>	<u>\$ 2,475.3</u>
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)	50.0	45.3
	<u>\$ 50.0</u>	<u>\$ 45.3</u>

- (1) As of September 30, 2013, availability under TRC’s \$150 million senior secured revolving credit facility was \$80.0 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 September 30, 2013, availability under the Partnership’s \$1.2 billion senior secured revolving credit facility was \$750.0 million.
- (4) The outstanding balance of the 11¼% Notes was redeemed on July 15, 2013. See “Senior Notes Repayments and Redemptions” below.
- (5) All amounts outstanding under the Partnership’s Securitization Facility are reflected as long-term debt in our balance sheet because the Partnership has the ability and intent to fund the Securitization Facility’s borrowing with availability under the Partnership’s Revolver (“the TRP Revolver”).

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

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

Compliance with Debt Covenants

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

The Partnership’s Accounts Receivable Securitization Facility

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

The Partnership's April 2013 Shelf

In April 2013, the Partnership filed with the SEC a universal shelf registration statement (the "April 2013 Shelf"), which provides the Partnership with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and the Partnership's capital needs. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the nine months ended September 30, 2013.

The Partnership's July 2013 Shelf

In July 2013, the Partnership filed with the SEC a universal shelf registration statement that allows it to issue up to an aggregate of \$800 million of debt or equity securities (the "July 2013 Shelf"). The July 2013 Shelf expires in August 2016. See Note 9 for equity issuances under the July 2013 Shelf.

The Partnership's 4¼% Senior Notes due 2023 ("4¼% Notes")

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

The 4¼% Notes are unsecured senior obligations that rank pari passu in right of payment with existing and future senior indebtedness. They are senior in right of payment to any of the Partnership's future subordinated indebtedness and are unconditionally guaranteed by certain of the Partnership's subsidiaries. The 4¼% Notes are effectively subordinated to all secured indebtedness under the Partnership's credit agreement, which is secured by substantially all of the Partnership's assets, to the extent of the value of the collateral securing that indebtedness.

Interest on the 4¼% Notes accrues at the rate of 4¼% per annum and is payable semi-annually in arrears on May 15 and November 15, commencing on November 15, 2013.

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

- 1) at least 65% of the aggregate principal amount of the 4¼% Notes (excluding the 4¼% Notes held by the Partnership) remains outstanding immediately after the occurrence of such redemption; and
- 2) the redemption occurs within 180 days of the date of the closing of such equity offering.

The Partnership may also redeem all or part of the 4¼% Notes on or after May 15, 2018 at the prices set forth below plus accrued and unpaid interest and liquidated damages, if any, on the notes redeemed, if redeemed during the twelve month period beginning on May 15 of each year indicated below.

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

Senior Notes Repayments and Redemptions

In June 2013, the Partnership paid \$106.4 million plus accrued interest, which included a premium of \$6.4 million, to redeem \$100 million of the outstanding 6¾% Senior Notes due 2022 (the "6¾% Notes"). The redemption resulted in a \$7.4 million loss on debt redemption, including the write-off of \$1.0 million of unamortized debt issue costs.

In July 2013, the Partnership paid \$76.8 million plus accrued interest, which included a premium of \$4.1 million, per the terms of the note agreement to redeem the outstanding balance of the 11¼% Senior Notes due 2017 (the "11¼% Notes"). The redemption resulted in a \$7.4 million loss on debt redemption in the third quarter 2013, including the write-off of \$1.0 million of unamortized debt issue costs.

Note 9 — Partnership Units and Related Matters

Public Offerings of Common Units

In 2012, the Partnership filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows the Partnership to issue up to an aggregate of \$300 million of debt or equity securities (the “2012 Shelf”). The 2012 Shelf expires in August 2015.

In August 2012, the Partnership entered into an Equity Distribution Agreement (“2012 EDA”) with Citigroup Global Markets Inc. (“Citigroup”) pursuant to which the Partnership may sell, at its option, up to an aggregate of \$100 million of its common units through Citibank, as sales agent, under the 2012 Shelf. Settlement for sales of common units occurs on the third business day following the date on which any sales were made. During the nine months ended September 30, 2013, the Partnership issued 2,420,046 common units under the 2012 EDA, receiving net proceeds of \$94.8 million. We contributed \$2.0 million to maintain our 2% general partner interest.

In March 2013, the Partnership entered into a second Equity Distribution Agreement under the 2012 Shelf (“March 2013 EDA”) with Citigroup, Deutsche Bank Securities Inc. (“Deutsche Bank”), Raymond James & Associates, Inc. (“Raymond James”) and UBS Securities LLC (“UBS”), as sales agents, pursuant to which the Partnership may sell, at its option, up to an aggregate of \$200 million of the Partnership common units. During the nine months ended September 30, 2013, the Partnership issued 4,204,751 common units, receiving net proceeds of \$197.5 million. During the nine months ended September 30, 2013, we contributed \$4.1 million to maintain our 2% general partner interest.

In August 2013, the Partnership entered into an Equity Distribution Agreement under the July 2013 Shelf (“August 2013 EDA”) with Citigroup, Deutsche Bank, Morgan Stanley & Co. LLC, Raymond James, RBC Capital Markets, LLC, UBS 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 the Partnership’s common units. During the third quarter of 2013, the Partnership issued 1,724,930 common units under the August 2013 EDA, receiving net proceeds of \$85.1 million, of which \$3.3 million was received in October 2013 and reported as a receivable in Owner’s Equity. We contributed \$1.8 million to the Partnership to maintain our 2% general partner interest, which we settled in October.

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 nine months ended September 30, 2013.

Three Months Ended	Date Paid or to be Paid	Distributions				Distributions to Targa Resources Corp.	Distributions per limited partner unit
		Limited Partners	General Partner		Total		
		Common	Incentive	2%			
(In millions, except per unit amounts)							
September 30, 2013	November 14, 2013	\$ 79.4	\$ 26.9	\$ 2.2	\$ 108.5	\$ 38.6	\$ 0.7325
June 30, 2013	August 14, 2013	75.8	24.6	2.0	102.4	35.9	0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	33.0	0.6975
December 31, 2012	February 14, 2013	69.0	20.1	1.8	90.9	30.7	0.6800

Note 10 — Common Stock and Related Matters

The following table details the dividends declared and/or paid by us for the nine months ended September 30, 2013:

<u>Three Months Ended</u>	<u>Date Paid or to be Paid</u>	<u>Total Dividend Declared</u>	<u>Amount of Dividend Paid</u>	<u>Accrued Dividends (1)</u>	<u>Dividend Declared per Share of Common Stock</u>
(In millions, except per share amounts)					
September 30, 2013	November 15, 2013	\$ 24.1	\$ 23.7	\$ 0.4	\$ 0.57000
June 30, 2013	August 15, 2013	22.5	22.1	0.4	0.53250
March 31, 2013	May 16, 2013	21.0	20.6	0.4	0.49500
December 31, 2012	February 15, 2013	19.4	19.0	0.4	0.45750

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

Note 11 — Earnings per Common Share

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

	<u>Three Months Ended September 30,</u>		<u>Nine Months Ended September 30,</u>	
	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
Net income	\$ 49.4	\$ 19.0	\$ 105.6	\$ 131.7
Less: Net income attributable to noncontrolling interests	33.1	10.3	61.0	104.8
Net income attributable to common shareholders	<u>\$ 16.3</u>	<u>\$ 8.7</u>	<u>\$ 44.6</u>	<u>\$ 26.9</u>
Weighted average shares outstanding - basic	<u>41.6</u>	<u>41.0</u>	<u>41.6</u>	<u>41.0</u>
Net income available per common share - basic	<u>\$ 0.39</u>	<u>\$ 0.21</u>	<u>\$ 1.07</u>	<u>\$ 0.66</u>
Weighted average shares outstanding	41.6	41.0	41.6	41.0
Dilutive effect of unvested stock awards	0.5	0.9	0.5	0.8
Weighted average shares outstanding - diluted	<u>42.1</u>	<u>41.9</u>	<u>42.1</u>	<u>41.8</u>
Net income available per common share - diluted	<u>\$ 0.39</u>	<u>\$ 0.21</u>	<u>\$ 1.06</u>	<u>\$ 0.64</u>

Note 12 — Derivative Instruments and Hedging Activities

Partnership Commodity Hedges

The primary purpose of the Partnership's commodity risk management activities is to manage its exposure to commodity price risk and reduce volatility in its operating cash flow due to fluctuations in commodity prices. The Partnership has hedged the commodity prices associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing segment and the LOU business unit in Coastal Gathering and Processing segment that result from its percent of proceeds processing arrangements. These hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices. The Partnership has designated these derivative contracts as cash flow hedges for accounting purposes.

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

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

At September 30, 2013, the notional volumes of the Partnership's commodity hedges for equity volumes were:

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

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

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

	Balance Sheet Location	Fair Value as of September 30, 2013		Fair Value as of December 31, 2012	
		Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	\$ 10.8	\$ 5.4	\$ 29.2	\$ 7.2
	Long-term	3.9	1.6	5.1	4.8
Total derivatives designated as hedging instruments		\$ 14.7	\$ 7.0	\$ 34.3	\$ 12.0
Derivatives not designated as hedging instruments					
Commodity contracts	Current	\$ 0.1	\$ 0.1	\$ 0.1	\$ 0.2
Total derivatives not designated as hedging instruments		\$ 0.1	\$ 0.1	\$ 0.1	\$ 0.2
Total current position		\$ 10.9	\$ 5.5	\$ 29.3	\$ 7.4
Total long-term position		3.9	1.6	5.1	4.8
Total derivatives		\$ 14.8	\$ 7.1	\$ 34.4	\$ 12.2

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

September 30, 2013	Gross Presentation		Pro forma Net Presentation	
	Asset Position	Liability Position	Asset Position	Liability Position
Current position				
Counterparties with offsetting position	\$ 10.3	\$ 3.8	\$ 6.5	\$ -
Counterparties without offsetting position - assets	0.6	-	0.6	-
Counterparties without offsetting position - liabilities	-	1.7	-	1.7
	<u>10.9</u>	<u>5.5</u>	<u>7.1</u>	<u>1.7</u>
Long-term position				
Counterparties with offsetting position	2.8	1.1	1.7	-
Counterparties without offsetting position - assets	1.1	-	1.1	-
Counterparties without offsetting position - liabilities	-	0.5	-	0.5
	<u>3.9</u>	<u>1.6</u>	<u>2.8</u>	<u>0.5</u>
Total derivatives				
Counterparties with offsetting position	13.1	4.9	8.2	-
Counterparties without offsetting position - assets	1.7	-	1.7	-
Counterparties without offsetting position - liabilities	-	2.2	-	2.2
	<u>\$ 14.8</u>	<u>\$ 7.1</u>	<u>\$ 9.9</u>	<u>\$ 2.2</u>
December 31, 2012				
Current position				
Counterparties with offsetting position	\$ 23.8	\$ 7.4	\$ 16.4	\$ -
Counterparties without offsetting position - assets	5.5	-	5.5	-
Counterparties without offsetting position - liabilities	-	-	-	-
	<u>29.3</u>	<u>7.4</u>	<u>21.9</u>	<u>-</u>
Long-term position				
Counterparties with offsetting position	4.4	2.8	1.6	-
Counterparties without offsetting position - assets	0.7	-	0.7	-
Counterparties without offsetting position - liabilities	-	2.0	-	2.0
	<u>5.1</u>	<u>4.8</u>	<u>2.3</u>	<u>2.0</u>
Total derivatives				
Counterparties with offsetting position	28.2	10.2	18.0	-
Counterparties without offsetting position - assets	6.2	-	6.2	-
Counterparties without offsetting position - liabilities	-	2.0	-	2.0
	<u>\$ 34.4</u>	<u>\$ 12.2</u>	<u>\$ 24.2</u>	<u>\$ 2.0</u>

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 asset of \$7.7 million as of September 30, 2013. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented.

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

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

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Commodity contracts	\$ (11.3)	\$ (22.6)	\$ 2.4	\$ 70.9
	<u>\$ (11.3)</u>	<u>\$ (22.6)</u>	<u>\$ 2.4</u>	<u>\$ 70.9</u>

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Interest expense, net	\$ (1.5)	\$ (1.9)	\$ (4.7)	\$ (6.1)
Revenues	4.5	15.4	17.0	31.7
	<u>\$ 3.0</u>	<u>\$ 13.5</u>	<u>\$ 12.3</u>	<u>\$ 25.6</u>

Hedge ineffectiveness was immaterial for all periods presented.

Our consolidated earnings are also affected by the Partnership’s use of the mark-to-market method of accounting for derivative instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the “mark-to-market” method) rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. Gain (loss) recognized on derivatives not designated as hedging instruments was immaterial for all periods presented.

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

	September 30, 2013	December 31, 2012
Commodity hedges, before tax	\$ 1.1	\$ 3.2
Commodity hedges, after tax	0.6	1.9
Interest rate hedges, before tax	(0.5)	(1.2)
Interest rate hedges, after tax	(0.3)	(0.7)

As of September 30, 2013, net gains of \$6.0 million on commodity hedges and net losses of \$3.8 million on terminated interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

See Note 13 for additional disclosures related to derivative instruments and hedging activities.

Note 13 — Fair Value Measurements

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

The following 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 swap and option contracts and fixed price commodity contracts with certain counterparties. The Partnership determines the fair value of its derivative contracts using a discounted cash flow model for swaps and a standard option pricing-model for options, based on inputs that are readily available in public markets. The Partnership has consistently applied these valuation techniques in all periods presented and we believe the Partnership has obtained the most accurate information available for the types of derivative contracts the Partnership holds.

The fair values of the Partnership’s derivative instruments, which aggregate to a net asset position of \$7.7 million as of September 30, 2013, are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This asset position reflects the present value, adjusted for counterparty credit risk, of the amount the Partnership expects to receive in the future on its derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net liability of \$12.4 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 \$27.8 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

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

- senior secured revolving credit facilities and the Partnership’s Securitization Facility are based on carrying value which approximates fair value as its interest rate is based on prevailing market rates;
- senior unsecured notes are based on quoted market prices derived from trades of the debt.

Fair Value Hierarchy

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

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and
- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

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

	September 30, 2013				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	\$ 14.8	\$ 14.8	\$ -	\$ 13.6	\$ 1.2
Liabilities from commodity derivative contracts	7.1	7.1	-	6.7	0.4
Badlands contingent consideration liability	-	-	-	-	-
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	83.7	83.7	-	-	-
TRC Senior secured revolving credit facility	70.0	70.0	-	70.0	-
Partnership's Senior secured revolving credit facility	400.0	400.0	-	400.0	-
Partnership's Senior unsecured notes	2,229.9	2,261.0	-	2,261.0	-
Partnership's accounts receivable securitization facility	168.0	168.0	-	168.0	-

	December 31, 2012				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	\$ 34.3	\$ 34.3	\$ -	\$ 34.3	\$ -
Liabilities from commodity derivative contracts	12.1	12.1	-	11.5	0.6
Badlands contingent consideration liability	15.3	15.3	-	-	15.3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	76.3	76.3	-	-	-
TRC Senior secured revolving credit facility	82.0	82.0	-	82.0	-
Partnership's Senior secured revolving credit facility	620.0	620.0	-	620.0	-
Partnership's Senior unsecured notes	1,773.3	1,945.2	-	1,945.2	-

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

As of September 30, 2013, we reported certain of the Partnership's natural gas basis swaps at fair value using Level 3 inputs due to such derivatives not having observable market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

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

As of September 30, 2013, the Partnership had nine natural gas basis swaps categorized as Level 3. The significant unobservable inputs used in the fair value measurements of the Partnership's Level 3 derivatives are the forward natural gas basis curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

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

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

	Commodity Derivative Contracts	Contingent Liability
Balance, December 31, 2012	\$ (0.6)	\$ (15.3)
Settlements included in Revenue	1.4	-
Change in valuation of contingent liability included in Other Income	-	15.3
Balance, September 30, 2013	<u>\$ 0.8</u>	<u>\$ -</u>

There has been no material transfer of assets or liabilities between the three levels of the fair value hierarchy during the nine months ended September 30, 2013.

Note 14 — Commitments and Contingencies

Environmental

On August 15, 2013, the Partnership received a notice of violation with a proposed penalty in the amount of \$130,600 from the New Mexico Environment Department (“NMED”) for alleged violations of certain air quality permit conditions at the Monument gas processing plant in Lea County, New Mexico, which is operated by the Partnership and owned by Versado Gas Processors, L.L.C. (“Versado”), a joint venture in which the Partnership owns a 63% interest. The Partnership is in discussions with the NMED to resolve this matter.

Legal Proceedings

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

Note 15 - Supplemental Cash Flow Information

	Nine Months Ended September 30,	
	2013	2012
Cash:		
Interest paid, net of capitalized interest	\$ 83.0	\$ 82.9
Income taxes paid, net of refunds	23.1	24.4
Non-cash:		
Deadstock inventory transferred to property, plant and equipment	28.3	2.9
Accrued dividends on unvested equity awards	1.1	1.6
Receivables from unit offerings	3.3	-
Change in capital accruals	3.8	9.3
Transfers from materials and supplies to property, plant and equipment	15.1	-
Change in ARO estimate	1.4	-

Note 16 — Segment Information

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

The Partnership's Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. With the Badlands acquisition on December 31, 2012, this segment's assets now includes the Badlands crude oil and natural gas gathering, terminaling and processing assets in North Dakota. Because the acquisition closed on December 31, 2012, Badlands had no operational impact for 2012. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

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

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

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

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

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

Three Months Ended September 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	\$ 56.5	\$ 71.1	\$ 38.8	\$ 1,249.5	\$ 4.8	\$ -	\$ (0.1)	\$ 1,420.6
Fees from midstream services	27.4	7.4	53.0	48.4	-	-	-	136.2
	<u>83.9</u>	<u>78.5</u>	<u>91.8</u>	<u>1,297.9</u>	<u>4.8</u>	<u>-</u>	<u>(0.1)</u>	<u>1,556.8</u>
Intersegment revenues								
Sales of commodities	318.9	163.1	1.8	118.5	-	(602.3)	-	-
Fees from midstream services	0.8	-	42.1	8.4	-	(51.3)	-	-
	<u>319.7</u>	<u>163.1</u>	<u>43.9</u>	<u>126.9</u>	<u>-</u>	<u>(653.6)</u>	<u>-</u>	<u>-</u>
Revenues	<u>\$ 403.6</u>	<u>\$ 241.6</u>	<u>\$ 135.7</u>	<u>\$ 1,424.8</u>	<u>\$ 4.8</u>	<u>\$ (653.6)</u>	<u>\$ (0.1)</u>	<u>\$ 1,556.8</u>
Operating margin	<u>\$ 70.6</u>	<u>\$ 21.1</u>	<u>\$ 70.5</u>	<u>\$ 32.5</u>	<u>\$ 4.8</u>	<u>\$ -</u>	<u>\$ (0.1)</u>	<u>\$ 199.4</u>
Other financial information:								
Total assets	<u>\$ 3,095.9</u>	<u>\$ 385.8</u>	<u>\$ 1,407.5</u>	<u>\$ 638.8</u>	<u>\$ 14.8</u>	<u>\$ 105.2</u>	<u>\$ 77.3</u>	<u>\$ 5,725.3</u>
Capital expenditures	<u>\$ 177.5</u>	<u>\$ 4.3</u>	<u>\$ 99.9</u>	<u>\$ 1.7</u>	<u>\$ -</u>	<u>\$ 1.1</u>	<u>\$ -</u>	<u>\$ 284.5</u>
Three Months Ended September 30, 2012								
Partnership								
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	\$ 42.2	\$ 60.5	\$ 52.9	\$ 1,136.4	\$ 14.0	\$ -	\$ 0.6	\$ 1,306.6
Fees from midstream services	8.5	7.4	43.6	27.4	-	-	-	86.9
	<u>50.7</u>	<u>67.9</u>	<u>96.5</u>	<u>1,163.8</u>	<u>14.0</u>	<u>-</u>	<u>0.6</u>	<u>1,393.5</u>
Intersegment revenues								
Sales of commodities	274.8	150.5	0.5	151.5	-	(577.3)	-	-
Fees from midstream services	0.3	-	27.6	7.2	-	(35.1)	-	-
	<u>275.1</u>	<u>150.5</u>	<u>28.1</u>	<u>158.7</u>	<u>-</u>	<u>(612.4)</u>	<u>-</u>	<u>-</u>
Revenues	<u>\$ 325.8</u>	<u>\$ 218.4</u>	<u>\$ 124.6</u>	<u>\$ 1,322.5</u>	<u>\$ 14.0</u>	<u>\$ (612.4)</u>	<u>\$ 0.6</u>	<u>\$ 1,393.5</u>
Operating margin	<u>\$ 53.8</u>	<u>\$ 18.0</u>	<u>\$ 50.4</u>	<u>\$ 25.4</u>	<u>\$ 14.0</u>	<u>\$ -</u>	<u>\$ 0.6</u>	<u>\$ 162.2</u>
Other financial information:								
Total assets	<u>\$ 1,717.3</u>	<u>\$ 421.8</u>	<u>\$ 977.5</u>	<u>\$ 491.7</u>	<u>\$ 44.8</u>	<u>\$ 117.8</u>	<u>\$ 110.6</u>	<u>\$ 3,881.5</u>
Capital expenditures	<u>\$ 66.7</u>	<u>\$ 28.2</u>	<u>\$ 64.0</u>	<u>\$ 0.9</u>	<u>\$ -</u>	<u>\$ 1.7</u>	<u>\$ -</u>	<u>\$ 161.5</u>

Nine Months Ended September 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	\$ 145.7	\$ 223.8	\$ 117.0	\$ 3,528.4	\$ 17.0	\$ -	\$ (0.2)	\$ 4,031.7	
Fees from midstream services	70.3	25.9	147.6	120.7	-	-	-	364.5	
	<u>216.0</u>	<u>249.7</u>	<u>264.6</u>	<u>3,649.1</u>	<u>17.0</u>	<u>-</u>	<u>(0.2)</u>	<u>4,396.2</u>	
Intersegment revenues									
Sales of commodities	882.9	450.9	3.6	354.7	-	(1,692.1)	-	-	
Fees from midstream services	2.4	-	111.8	20.8	-	(135.0)	-	-	
	<u>885.3</u>	<u>450.9</u>	<u>115.4</u>	<u>375.5</u>	<u>-</u>	<u>(1,827.1)</u>	<u>-</u>	<u>-</u>	
Revenues	<u>\$ 1,101.3</u>	<u>\$ 700.6</u>	<u>\$ 380.0</u>	<u>\$ 4,024.6</u>	<u>\$ 17.0</u>	<u>\$ (1,827.1)</u>	<u>\$ (0.2)</u>	<u>\$ 4,396.2</u>	
Operating margin	<u>\$ 191.8</u>	<u>\$ 61.2</u>	<u>\$ 178.9</u>	<u>\$ 94.0</u>	<u>\$ 17.0</u>	<u>\$ -</u>	<u>\$ (0.3)</u>	<u>\$ 542.6</u>	
Other financial information:									
Total assets	<u>\$ 3,095.9</u>	<u>\$ 385.8</u>	<u>\$ 1,407.5</u>	<u>\$ 638.8</u>	<u>\$ 14.8</u>	<u>\$ 105.2</u>	<u>\$ 77.3</u>	<u>\$ 5,725.3</u>	
Capital expenditures	<u>\$ 388.8</u>	<u>\$ 15.1</u>	<u>\$ 317.7</u>	<u>\$ 2.4</u>	<u>\$ -</u>	<u>\$ 3.1</u>	<u>\$ -</u>	<u>\$ 727.1</u>	

Nine Months Ended September 30, 2012

	Partnership								
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated	
Revenues									
Sales of commodities	\$ 134.2	\$ 172.0	\$ 152.9	\$ 3,622.2	\$ 28.1	\$ -	\$ 1.6	\$ 4,111.0	
Fees from midstream services	27.3	15.9	125.6	78.5	-	0.1	-	247.4	
	<u>161.5</u>	<u>187.9</u>	<u>278.5</u>	<u>3,700.7</u>	<u>28.1</u>	<u>0.1</u>	<u>1.6</u>	<u>4,358.4</u>	
Intersegment revenues									
Sales of commodities	851.9	532.7	0.6	398.3	-	(1,783.5)	-	-	
Fees from midstream services	0.9	0.1	76.2	23.5	-	(100.7)	-	-	
	<u>852.8</u>	<u>532.8</u>	<u>76.8</u>	<u>421.8</u>	<u>-</u>	<u>(1,884.2)</u>	<u>-</u>	<u>-</u>	
Revenues	<u>\$ 1,014.3</u>	<u>\$ 720.7</u>	<u>\$ 355.3</u>	<u>\$ 4,122.5</u>	<u>\$ 28.1</u>	<u>\$ (1,884.1)</u>	<u>\$ 1.6</u>	<u>\$ 4,358.4</u>	
Operating margin	<u>\$ 180.6</u>	<u>\$ 92.3</u>	<u>\$ 139.2</u>	<u>\$ 77.8</u>	<u>\$ 28.1</u>	<u>\$ -</u>	<u>\$ 1.4</u>	<u>\$ 519.4</u>	
Other financial information:									
Total assets	<u>\$ 1,717.3</u>	<u>\$ 421.8</u>	<u>\$ 977.5</u>	<u>\$ 491.7</u>	<u>\$ 44.8</u>	<u>\$ 117.8</u>	<u>\$ 110.6</u>	<u>\$ 3,881.5</u>	
Capital expenditures	<u>\$ 139.6</u>	<u>\$ 32.8</u>	<u>\$ 213.8</u>	<u>\$ 10.4</u>	<u>\$ -</u>	<u>\$ 3.2</u>	<u>\$ 0.4</u>	<u>\$ 400.2</u>	

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Sales of commodities				
Natural gas sales	\$ 317.7	\$ 252.1	\$ 920.5	\$ 642.7
NGL sales	1,025.2	957.4	2,885.6	3,198.4
Condensate sales	35.3	29.0	95.3	87.0
Petroleum products	37.9	52.7	113.4	152.5
Derivative activities	4.5	15.4	16.9	30.4
	<u>1,420.6</u>	<u>1,306.6</u>	<u>4,031.7</u>	<u>4,111.0</u>
Fees from midstream services				
Fractionating and treating fees	38.2	28.6	98.9	84.0
Storage, terminaling, transportation and export fees	63.0	41.6	170.3	107.4
Gathering and processing fees	30.0	11.8	75.5	30.1
Other	5.0	4.9	19.8	25.9
	<u>136.2</u>	<u>86.9</u>	<u>364.5</u>	<u>247.4</u>
Total revenues	<u>\$ 1,556.8</u>	<u>\$ 1,393.5</u>	<u>\$ 4,396.2</u>	<u>\$ 4,358.4</u>

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Operating margin	\$ 199.4	\$ 162.2	\$ 542.6	\$ 519.4
Depreciation and amortization expense	(69.0)	(48.6)	(198.7)	(144.3)
General and administrative expense	(37.7)	(35.7)	(112.5)	(106.5)
Interest expense, net	(33.4)	(30.0)	(97.9)	(91.0)
Income tax expense	(13.0)	(6.0)	(30.3)	(24.7)
Other, net	3.1	(22.9)	2.4	(21.2)
Net income	<u>\$ 49.4</u>	<u>\$ 19.0</u>	<u>\$ 105.6</u>	<u>\$ 131.7</u>

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management’s Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2012 (“Annual Report”), as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Financial Presentation

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

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

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

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

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

- noncontrolling interests in the Partnership;
- our separate debt obligations;
- certain general and administrative costs applicable to us as a separate public company;
- certain non-operating assets and liabilities that we retained; and
- federal income taxes.

Our Operations

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

The Partnership's Operations

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

- gathering, compressing, treating, processing and selling natural gas;
- storing, fractionating, treating, transporting and selling NGLs and NGL products;
- gathering, storing and terminaling crude oil; and
- storing, terminaling and selling refined petroleum products.

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

The Partnership's Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. With the Badlands acquisition on December 31, 2012, this segment's assets now include the Badlands crude oil and natural gas gathering, terminaling and processing assets in North Dakota. Because the acquisition closed on December 31, 2012, Badlands had no operational impact for 2012. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

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

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

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

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

2013 Developments

Badlands Acquisition

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

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

Changes in the fair value of this accrued liability are included in earnings and reported as Other income (expense) in the Consolidated Statement of Operations. As of September 30, 2013, the contingent consideration was re-estimated to be \$0, resulting in an increase in Other income of \$9.1 million for third quarter 2013 and \$15.3 million year-to-date 2013. The elimination of the contingent liability reflects management’s updated assessment as discussed above, related to producer volumes required to meet the contingent volume thresholds.

Cedar Bayou Fractionators Train 4

In August 2013, the Partnership commissioned an additional fractionator, Train 4, at its majority owned joint venture Cedar Bayou Fractionators (“CBF”) in Mont Belvieu, Texas. This expansion adds 100,000 barrels per day of fractionation capacity at CBF.

International Export Project

In September 2013, the Partnership commissioned Phase I of its international export expansion project, which includes facilities both at its Mont Belvieu operations and at its Galena Park Marine Terminal near Houston, Texas. Phase I of this project adds the capability to export approximately 2,000,000 barrels per month of international grade, low ethane propane or butane.

Accounts Receivable Securitization Facility

In January 2013, the Partnership entered into a Securitization Facility that provides up to \$200 million of borrowing capacity at commercial paper or LIBOR market index rates plus a margin through January 2014. Under this Securitization Facility, one of the Partnership’s consolidated subsidiaries (TLMT) sells or contributes receivables, without recourse, to another of the Partnership’s consolidated subsidiaries (TRLIC), a special purpose consolidated subsidiary created for the sole purpose of this Securitization Facility. TRLIC, in turn, sells an undivided percentage ownership in the eligible receivables to a third-party financial institution. Receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of TLMT or us. Any excess receivables are eligible to satisfy the claims of creditors of TLMT or us. Total funding under this Securitization Facility as of September 30, 2013 was \$168.0 million.

Other Financing Activities

In April 2013, the Partnership filed with the SEC a universal shelf registration statement (the April 2013 Shelf), which provides the Partnership with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and the Partnership’s capital needs. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the nine months ended September 30, 2013.

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

In June 2013, the Partnership redeemed \$100 million of the outstanding 6¾% Notes at a redemption price of 106.375% plus accrued interest through the redemption date using proceeds from the March 2013 EDA. The redemption resulted in a \$7.4 million loss, including the write-off of unamortized debt issue costs.

In July 2013, the Partnership redeemed the outstanding 11¼% Notes at a price of 105.625% plus accrued interest through July 15, 2013. The redemption resulted in a \$7.4 million loss, including the write-off of unamortized debt issue costs.

In July 2013, the Partnership filed with the SEC a universal shelf registration statement (the July 2013 Shelf) that allows us to issue up to an aggregate of \$800 million of debt or equity securities. The July 2013 Shelf expires in August 2016.

In August 2013, the Partnership entered into an Equity Distribution Agreement under its July 2013 Shelf (August 2013 EDA) with Citigroup, Deutsche Bank, Morgan Stanley & Co. LLC, Raymond James, RBC Capital Markets, LLC, UBS and Wells Fargo Securities, LLC, as its sales agents, pursuant to which it may sell, at its option, up to an aggregate of \$400 million of its common units. During the nine months ended September 30, 2013, the Partnership issued 1,724,930 common units under the August 2013 EDA, receiving net proceeds of \$81.8 million, and an additional \$3.3 million in October 2013. We contributed \$1.8 million to maintain our 2% general partner interest, which we settled in October 2013. Based upon market conditions and the Partnership's capital needs, the Partnership at its option, can sell additional common units up to an aggregate amount of \$313.9 million under this agreement.

During the nine months ended September 30, 2013, pursuant to both the 2012 Shelf and 2013 Shelf, the Partnership issued a total of 8,349,727 common units representing total net proceeds of \$377.4 million. We contributed \$7.9 million to the Partnership to maintain our 2% general partner interest during this period.

Recent Accounting Pronouncements

In January 2013, the FASB issued Accounting Standards Update No. 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*, which clarifies that ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*, applies to financial instruments or derivative transactions accounted for under ASC 815. We currently present our derivative assets and liabilities gross on our statement of financial position. The amendments require disclosure of both gross and net amounts of derivative assets and liabilities that are subject to master netting arrangements with counterparties. We have provided additional disclosures regarding the gross and net amounts of derivative assets and liabilities in Note 12.

How We Evaluate Our Operations

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

Distributable Cash Flow

We define distributable cash flow as distributions due to us from the Partnership, less our specific general and administrative costs as a separate public reporting entity, the interest carry costs associated with our debt and taxes attributable to our earnings. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts, and others to compare basic cash flows generated by us to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash dividends. Distributable cash flow is also an important financial measure for our shareholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether 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.

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.

Our Non-GAAP Measures

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In millions)			
Reconciliation of net income attributable to Targa Resources Corp. to distributable Cash Flow				
Net income of Targa Resources Corp.	\$ 49.4	\$ 19.0	\$ 105.6	\$ 131.7
Less: Net income of Targa Resources Partners LP	(65.0)	(28.1)	(143.0)	(164.7)
Net loss for TRC Non-Partnership	(15.6)	(9.1)	(37.4)	(33.0)
TRC Non-Partnership income tax expense	12.3	5.1	27.8	22.0
Distributions from the Partnership	38.6	26.2	107.5	72.6
Non-cash loss (gain) on hedges	0.1	(0.6)	0.2	(1.6)
Depreciation - Non-Partnership	0.1	0.7	0.2	2.2
Current cash tax expense, net (1)	(1.9)	(2.6)	(15.2)	(15.2)
Taxes funded with cash on hand (2)	1.9	2.2	6.9	6.6
Targa Resources Corp. distributable cash flow	<u>\$ 35.5</u>	<u>\$ 21.9</u>	<u>\$ 90.0</u>	<u>\$ 53.6</u>

- (1) Excludes \$1.2 million and \$3.6 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 nine months ended September 30, 2013 and 2012, and includes 2012 cash tax overpayment applied to 2013 cash tax liability.
- (2) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop-down transactions that were treated as sales for income tax purposes.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In millions)			
Targa Resources Corp. distributable Cash Flow				
Distributions declared by Targa Resources Partners LP associated with:				
General Partner Interests	\$ 2.2	\$ 1.5	\$ 6.1	\$ 4.4
Incentive Distribution Rights	26.9	16.1	73.6	43.2
Common Units	9.5	8.6	27.8	25.0
Total distributions declared by Targa Resources Partners LP	38.6	26.2	107.5	72.6
Income (expenses) of TRC Non-Partnership				
General and administrative expenses	(2.3)	(2.2)	(6.8)	(6.5)
Interest expense, net	(0.8)	(1.0)	(2.3)	(3.2)
Current cash tax expense, net (1)	(1.9)	(2.6)	(15.2)	(15.2)
Taxes funded with cash on hand (2)	1.9	2.2	6.9	6.6
Other income (expense)	-	(0.7)	(0.1)	(0.7)
Targa Resources Corp. distributable cash flow	<u>\$ 35.5</u>	<u>\$ 21.9</u>	<u>\$ 90.0</u>	<u>\$ 53.6</u>

- (1) Excludes \$1.2 million and \$3.6 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 nine months ended September 30, 2013 and 2012, and includes 2012 cash tax overpayment applied to 2013 cash tax liability.
- (2) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop-down transactions that were treated as sales for income tax purposes.

How We Evaluate the Partnership's Operations

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

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

Management uses a variety of financial measures and operational measurements to analyze the Partnership's performance. These include: (1) throughput volumes, facility efficiencies and fuel consumption, (2) operating expenses, (3) capital expenditures and (4) the following non-GAAP measures—gross margin, operating margin, adjusted EBITDA and distributable cash flow.

Throughput Volumes, Facility Efficiencies and Fuel Consumption

The Partnership's profitability is impacted by its ability to add new sources of natural gas supply and crude oil to offset the natural decline of existing volumes from oil and natural gas wells that are connected to its gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production, as well as by capturing crude oil and natural gas supplies currently gathered by third-parties. Similarly, the Partnership's profitability is impacted by its ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to its Downstream Business' fractionation facilities. The Partnership fractionates NGLs generated by its gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities. The Partnership's recently acquired assets in the Bakken Shale should allow it to participate in the infrastructure build-out in return for fee-based revenue to gather crude oil or gather and process natural gas, from the wellhead to various takeaway options. There is a significant amount of uncommitted acreage in proximity to the Partnership's system, which should provide further opportunities to enhance medium and long-term growth in the Bakken Shale.

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

As part of monitoring the efficiency of its operations, the Partnership measures the difference between the volume of natural gas received at the wellhead or central delivery points on its gathering systems and the volume received at the inlet of its processing plants as an indicator of fuel consumption and line loss. The Partnership also tracks the difference between the volume of natural gas received at the inlet of the processing plant and the NGLs and residue gas produced at the outlet of such plant to monitor the fuel consumption and recoveries of the facilities. Similar tracking is performed for its crude oil gathering and logistics assets. These volume, recovery and fuel consumption measurements are an important part of the Partnership's operational efficiency analysis and safety programs.

Operating Expenses

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

Capital Expenditures

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

Gross Margin

The Partnership defines gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as the Partnership's contract mix and hedging program. The Partnership defines Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate and NGLs (2) natural gas and crude oil gathering and service fee revenues and (3) settlement gains and losses on commodity hedges, less product purchases, which consist primarily of producer payments and other natural gas purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees, NGL and natural gas sales, less cost of sales, which consists primarily of NGL and natural gas purchases, transportation costs and changes in inventory valuation.

Operating Margin

The Partnership defines operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of the Partnership's operations.

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

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

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

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

Adjusted EBITDA

The Partnership defines Adjusted EBITDA as net income before: interest; income taxes; depreciation and amortization; gains or losses on debt repurchases and redemptions, early debt extinguishments and asset disposals; non-cash risk management activities related to derivative instruments; and changes in the fair value of the Badlands acquisition contingent consideration. Adjusted EBITDA is used as a supplemental financial measure by the Partnership and by external users of our financial statements such as investors, commercial banks and others.

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

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

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

Distributable Cash Flow

The Partnership defines distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash 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.

Distributable cash flow is a significant performance metric used by the Partnership and by external users of the Partnership's financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by the Partnership (prior to the establishment of any retained cash reserves by the board of directors of its general partner) to the cash distributions the Partnership expects to pay the Partnership's unitholders. Using this metric, the Partnership's management and external users of its financial statements can quickly compute the coverage ratio of estimated cash flows to cash distributions. Distributable cash flow is also an important financial measure for the Partnership's unitholders since it serves as an indicator of the Partnership's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether the Partnership is generating cash flow at a level that can sustain or support an increase in the Partnership's quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

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

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

Non-GAAP Financial Measures of the Partnership

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

	<u>Three Months Ended September 30,</u>		<u>Nine Months Ended September 30,</u>	
	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
	(In millions)			
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:				
Gross margin	\$ 297.1	\$ 239.9	\$ 822.6	\$ 745.1
Operating expenses	(97.6)	(78.3)	(279.7)	(227.1)
Operating margin	199.5	161.6	542.9	518.0
Depreciation and amortization expenses	(68.9)	(47.9)	(198.5)	(142.1)
General and administrative expenses	(35.4)	(33.5)	(105.7)	(100.0)
Interest expense, net	(32.6)	(29.0)	(95.6)	(87.8)
Income tax expense	(0.7)	(0.9)	(2.5)	(2.7)
Gain (loss) on sale or disposition of assets	0.7	(15.6)	(3.1)	(15.5)
Loss on debt redemption and early debt extinguishments	(7.4)	-	(14.7)	-
Change in contingent consideration	9.1	-	15.3	-
Other, net	0.7	(6.6)	4.9	(5.2)
Targa Resources Partners LP Net income	<u>\$ 65.0</u>	<u>\$ 28.1</u>	<u>\$ 143.0</u>	<u>\$ 164.7</u>

	<u>Three Months Ended September 30,</u>		<u>Nine Months Ended September 30,</u>	
	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
	(In millions)			
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:				
Net cash provided by operating activities	\$ 99.5	\$ 90.5	\$ 276.3	\$ 315.5
Net income attributable to noncontrolling interests	(5.3)	(3.9)	(18.1)	(23.5)
Interest expense, net (1)	28.8	24.5	83.8	74.2
Loss on debt redemption and early debt extinguishments	(7.4)	-	(14.7)	-
Change in contingent consideration	(9.1)	-	(15.3)	-
Current income tax expense	0.7	0.5	1.7	1.5
Other (2)	(3.0)	(5.3)	(1.9)	(14.5)
Changes in operating assets and liabilities which used (provided) cash:				
Accounts receivable and other assets	124.9	42.6	93.4	(166.1)
Accounts payable and other liabilities	(73.2)	(32.7)	9.4	197.3
Targa Resources Partners LP Adjusted EBITDA	<u>\$ 155.9</u>	<u>\$ 116.2</u>	<u>\$ 414.6</u>	<u>\$ 384.4</u>

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of \$3.8 million and \$4.5 million for the three months ended September 30, 2013 and 2012, and \$11.8 million and \$13.6 million for the nine months ended September 30, 2013 and 2012.

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

<u>Three Months Ended September 30,</u>		<u>Nine Months Ended September 30,</u>	
<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>

(In millions)

Reconciliation of net income attributable to Targa Resources Partners

LP to Adjusted EBITDA:

Net income attributable to Targa Resources Partners LP	\$ 59.7	\$ 24.2	\$ 124.9	\$ 141.2
Interest expense, net	32.6	29.0	95.6	87.8
Income tax expense	0.7	0.9	2.5	2.7
Depreciation and amortization expenses	68.9	47.9	198.5	142.1
(Gain) loss on sale or disposition of assets	(0.7)	15.6	3.1	15.5
Loss on debt redemption and early debt extinguishments	7.4	-	14.7	-
Change in contingent consideration	(9.1)	-	(15.3)	-
Risk management activities	(0.3)	1.6	(0.2)	3.8
Noncontrolling interests adjustment (1)	(3.3)	(3.0)	(9.2)	(8.7)
Targa Resources Partners LP Adjusted EBITDA	<u>\$ 155.9</u>	<u>\$ 116.2</u>	<u>\$ 414.6</u>	<u>\$ 384.4</u>

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

<u>Three Months Ended September 30,</u>		<u>Nine Months Ended September 30,</u>	
<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>

(In millions)

Reconciliation of net income attributable to Targa Resources Partners

LP to distributable cash flow:

Net income attributable to Targa Resources Partners LP	\$ 59.7	\$ 24.2	\$ 124.9	\$ 141.2
Depreciation and amortization expenses	68.9	47.9	198.5	142.1
Deferred income tax expense	-	0.4	0.8	1.2
Amortization in interest expense	3.8	4.5	11.8	13.6
Loss on debt redemption and early debt extinguishment	7.4	-	14.7	-
Change in contingent consideration	(9.1)	-	(15.3)	-
(Gain) loss on sale or disposition of assets	(0.7)	15.6	3.1	15.5
Risk management activities	(0.3)	1.6	(0.2)	3.8
Maintenance capital expenditures	(17.0)	(16.2)	(60.4)	(48.0)
Other (1)	(1.9)	(0.8)	(2.5)	(1.8)
Targa Resources Partners LP distributable cash flow	<u>\$ 110.8</u>	<u>\$ 77.2</u>	<u>\$ 275.4</u>	<u>\$ 267.6</u>

(1) Includes the noncontrolling interest portion of maintenance capital expenditures, depreciation and amortization expenses.

Financial Information – Partnership versus Non-Partnership

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

Balance Sheets – Partnership versus Non-Partnership

	September 30, 2013			December 31, 2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
(In millions)						
ASSETS						
Current assets:						
Cash and cash equivalents (1)	\$ 83.7	\$ 74.1	\$ 9.6	\$ 76.3	\$ 68.0	\$ 8.3
Trade receivables, net	498.5	498.5	-	514.9	514.9	-
Inventory	201.7	201.7	-	99.4	99.4	-
Assets from risk management activities	10.9	10.9	-	29.3	29.3	-
Other current assets (1)	14.2	3.5	10.7	13.4	3.3	10.1
Total current assets	809.0	788.7	20.3	733.3	714.9	18.4
Property, plant and equipment, at cost (1)	5,454.0	5,447.2	6.8	4,708.0	4,701.2	6.8
Accumulated depreciation	(1,344.6)	(1,342.4)	(2.2)	(1,170.0)	(1,168.0)	(2.0)
Property, plant and equipment, net	4,109.4	4,104.8	4.6	3,538.0	3,533.2	4.8
Other intangible assets, net	660.3	660.3	-	680.8	680.8	-
Long-term assets from risk management activities	3.9	3.9	-	5.1	5.1	-
Other long-term assets (2)	142.7	90.3	52.4	147.8	91.7	56.1
Total assets	\$ 5,725.3	\$ 5,648.0	\$ 77.3	\$ 5,105.0	\$ 5,025.7	\$ 79.3
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (3)	\$ 679.6	\$ 650.3	\$ 29.3	\$ 679.0	\$ 639.8	\$ 39.2
Affiliate payable (receivable) (4)	-	46.9	(46.9)	-	61.4	(61.4)
Deferred income taxes (5)	2.0	-	2.0	0.2	-	0.2
Liabilities from risk management activities	5.5	5.5	-	7.4	7.4	-
Total current liabilities	687.1	702.7	(15.6)	686.6	708.6	(22.0)
Long-term debt	2,867.9	2,797.9	70.0	2,475.3	2,393.3	82.0
Long-term liabilities from risk management activities	1.6	1.6	-	4.8	4.8	-
Deferred income taxes (5)	136.1	12.0	124.1	131.2	11.2	120.0
Other long-term liabilities (6)	58.0	51.8	6.2	53.7	47.7	6.0
Total liabilities	3,750.7	3,566.0	184.7	3,351.6	3,165.6	186.0
Total owners' equity	1,974.6	2,082.0	(107.4)	1,753.4	1,860.1	(106.7)
Total liabilities and owners' equity	\$ 5,725.3	\$ 5,648.0	\$ 77.3	\$ 5,105.0	\$ 5,025.7	\$ 79.3

The major Non-Partnership balance sheet items relate to:

- (1) Corporate assets consisting of cash and prepaid insurance, as applicable.
- (2) Long-term tax assets primarily related to gains on 2010 drop-down transactions recognized as sales of assets for tax purposes.
- (3) Accrued current employee liabilities related to payroll and incentive compensation plans and taxes payable.
- (4) Intercompany receivable with the Partnership.
- (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.

Results of Operations – Partnership versus Non-Partnership

	Three Months Ended September 30,					
	2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Revenues (1)	\$ 1,556.8	\$ 1,556.9	\$ (0.1)	\$ 1,393.5	\$ 1,392.9	\$ 0.6
Costs and Expenses:						
Product purchases	1,259.8	1,259.8	-	1,153.0	1,153.0	-
Operating expenses	97.6	97.6	-	78.3	78.3	-
Depreciation and amortization (2)	69.0	68.9	0.1	48.6	47.9	0.7
General and administrative (3)	37.7	35.4	2.3	35.7	33.5	2.2
Other operating (income) expense	4.2	4.2	-	18.9	18.9	-
Income from operations	88.5	91.0	(2.5)	59.0	61.3	(2.3)
Other income (expense):						
Interest expense, net - third party (4)	(33.4)	(32.6)	(0.8)	(30.0)	(29.0)	(1.0)
Equity earnings (loss)	5.6	5.6	-	(2.2)	(2.2)	-
Loss on debt redemption	(7.4)	(7.4)	-	-	-	-
Other income (expense)	9.1	9.1	-	(1.8)	(1.1)	(0.7)
Income (loss) before income taxes	62.4	65.7	(3.3)	25.0	29.0	(4.0)
Income tax expense (5)	(13.0)	(0.7)	(12.3)	(6.0)	(0.9)	(5.1)
Net income (loss)	\$ 49.4	\$ 65.0	\$ (15.6)	\$ 19.0	\$ 28.1	\$ (9.1)
Less: Net income attributable to noncontrolling interests (6)	33.1	5.3	27.8	10.3	3.9	6.4
Net income (loss) after noncontrolling interests	\$ 16.3	\$ 59.7	\$ (43.4)	\$ 8.7	\$ 24.2	\$ (15.5)

The major Non-Partnership results of operations relate to:

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

	Nine Months Ended September 30,					
	2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
Revenues (1)	\$ 4,396.2	\$ 4,396.4	\$ (0.2)	\$ 4,358.4	\$ 4,356.8	\$ 1.6
Costs and Expenses:						
Product purchases	3,573.8	3,573.8	-	3,611.8	3,611.7	0.1
Operating expenses	279.8	279.7	0.1	227.2	227.1	0.1
Depreciation and amortization (2)	198.7	198.5	0.2	144.3	142.1	2.2
General and administrative (3)	112.5	105.7	6.8	106.5	100.0	6.5
Other operating (income) expense	8.3	8.3	-	18.8	18.8	-
Income from operations	223.1	230.4	(7.3)	249.8	257.1	(7.3)
Other income (expense):						
Interest expense, net - third party (4)	(97.9)	(95.6)	(2.3)	(91.0)	(87.8)	(3.2)
Equity earnings (loss)	10.1	10.1	-	(0.3)	(0.3)	-
Loss on debt redemption	(14.7)	(14.7)	-	-	-	-
Other income (expense)	15.3	15.3	-	(2.1)	(1.6)	(0.5)
Income (loss) before income taxes	135.9	145.5	(9.6)	156.4	167.4	(11.0)
Income tax expense (5)	(30.3)	(2.5)	(27.8)	(24.7)	(2.7)	(22.0)
Net income (loss)	\$ 105.6	\$ 143.0	\$ (37.4)	\$ 131.7	\$ 164.7	\$ (33.0)
Less: Net income attributable to noncontrolling interests (6)	61.0	18.1	42.9	104.8	23.5	81.3
Net income (loss) after noncontrolling interests	\$ 44.6	\$ 124.9	\$ (80.3)	\$ 26.9	\$ 141.2	\$ (114.3)

The major Non-Partnership results of operations relate to:

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

(6) TRC noncontrolling interest in the Partnership.

Nine Months Ended September 30,

	2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
(In millions)						
Cash flows from operating activities						
Net income (loss)	\$ 105.6	\$ 143.0	\$ (37.4)	\$ 131.7	\$ 164.7	\$ (33.0)
Adjustments to reconcile net income to net cash provided by operating activities:						
Amortization in interest expense (1)	12.1	11.8	0.3	14.7	13.6	1.1
Compensation on equity grants (2)	10.0	4.4	5.6	13.0	2.6	10.4
Depreciation and amortization expense (3)	198.7	198.5	0.2	144.3	142.1	2.2
Accretion of asset retirement obligations	3.0	3.0	-	3.0	2.9	0.1
Deferred income tax expense (4)	7.0	0.8	6.2	4.4	1.2	3.2
Equity earnings, net of distributions	-	-	-	0.3	0.3	-
Risk management activities (5)	-	(0.2)	0.2	1.7	3.8	(2.1)
Loss (gain) on sale of assets	3.1	3.1	-	15.5	15.5	-
Loss on debt redemption	14.7	14.7	-	-	-	-
Changes in operating assets and liabilities (6)	(96.1)	(102.8)	6.7	(38.4)	(31.2)	(7.2)
Net cash provided by (used in) operating activities	258.1	276.3	(18.2)	290.2	315.5	(25.3)
Cash flows from investing activities						
Outlays for property, plant and equipment (3)	(708.2)	(708.2)	-	(365.1)	(364.8)	(0.3)
Business acquisitions, net of cash acquired	-	-	-	(25.8)	(25.8)	-
Purchase of materials and supplies	(35.3)	(35.3)	-	-	-	-
Investment in unconsolidated affiliate	-	-	-	(16.8)	(16.8)	-
Return of capital from unconsolidated affiliate	1.9	1.9	-	2.3	2.3	-
Other	4.0	4.0	-	1.6	1.6	-
Net cash used in investing activities	(737.6)	(737.6)	-	(403.8)	(403.5)	(0.3)
Cash flows from financing activities						
Loan Facilities - Partnership:						
Borrowings	1,743.0	1,743.0	-	1,120.0	1,120.0	-
Repayments	(1,521.2)	(1,521.2)	-	(938.0)	(938.0)	-
Accounts receivable securitization facility - Partnership						
Borrowings	261.6	261.6	-	-	-	-
Repayments	(93.6)	(93.6)	-	-	-	-
Loan Facilities - Non-Partnership:						
Borrowings (1)	36.0	-	36.0	-	-	-
Repayments (1)	(48.0)	-	(48.0)	-	-	-
Costs incurred in connection with financing arrangements	(13.6)	(13.6)	-	(10.0)	(10.0)	-
Proceeds from sale of common units of the Partnership, net (7)	379.6	385.7	(6.1)	120.7	173.8	(53.1)
Distributions to owners (8)	(195.1)	(294.5)	99.4	(159.3)	(225.4)	66.1
Dividends to common and common equivalent shareholders	(61.8)	-	(61.8)	(44.9)	-	(44.9)
Contributions (distributions) (9)	-	-	-	-	0.9	(0.9)
Net cash provided by (used in) financing activities	486.9	467.4	19.5	88.5	121.3	(32.8)
Net change in cash and cash equivalents	7.4	6.1	1.3	(25.1)	33.3	(58.4)
Cash and cash equivalents, beginning of period	76.3	68.0	8.3	145.8	55.6	90.2
Cash and cash equivalents, end of period	\$ 83.7	\$ 74.1	\$ 9.6	\$ 120.7	\$ 88.9	\$ 31.8

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) Cash and non-cash activity related to corporate administrative assets.
- (4) TRC's federal and state income taxes.
- (5) Non-cash OCI hedge realizations related to predecessor operations.
- (6) See Balance Sheet – Partnership versus Non-Partnership for a description of the Non-Partnership operating assets and liabilities.
- (7) Contributions to the Partnership to maintain 2% General Partner ownership and in 2012 to purchase the limited partner units.
- (8) Distributions received by TRC from the Partnership for its general partner interest, limited partner interest and IDRs.
- (9) Other activity with the Partnership.

Consolidated Results of Operations

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

	Three Months Ended September 30,		2013 vs. 2012		Nine Months Ended September 30,		2013 vs. 2012	
	2013	2012			2013	2012		
(In millions, except operating statistics and price amounts)								
Revenues	\$ 1,556.8	\$ 1,393.5	\$ 163.3	12%	\$ 4,396.2	\$ 4,358.4	\$ 37.8	1%
Product purchases	1,259.8	1,153.0	106.8	9%	3,573.8	3,611.8	(38.0)	(1%)
Gross margin (1)	297.0	240.5	56.5	23%	822.4	746.6	75.8	10%
Operating expenses	97.6	78.3	19.3	25%	279.8	227.2	52.6	23%
Operating margin (2)	199.4	162.2	37.2	23%	542.6	519.4	23.2	4%
Depreciation and amortization expenses	69.0	48.6	20.4	42%	198.7	144.3	54.4	38%
General and administrative expenses	37.7	35.7	2.0	6%	112.5	106.5	6.0	6%
Other operating (income) expense	4.2	18.9	(14.7)	(78%)	8.3	18.8	(10.5)	(56%)
Income from operations	88.5	59.0	29.5	50%	223.1	249.8	(26.7)	(11%)
Interest expense, net	(33.4)	(30.0)	(3.4)	11%	(97.9)	(91.0)	(6.9)	8%
Equity earnings (loss)	5.6	(2.2)	7.8	NM	10.1	(0.3)	10.4	NM
Loss on debt redemption	(7.4)	-	(7.4)	0%	(14.7)	-	(14.7)	0%
Other	9.1	(1.8)	10.9	NM	15.3	(2.1)	17.4	NM
Income tax expense	(13.0)	(6.0)	(7.0)	117%	(30.3)	(24.7)	(5.6)	23%
Net income	49.4	19.0	30.4	160%	105.6	131.7	(26.1)	(20%)
Less: Net income attributable to noncontrolling interests	33.1	10.3	22.8	221%	61.0	104.8	(43.8)	(42%)
Net income (loss) available to common shareholders	\$ 16.3	\$ 8.7	\$ 7.6	87%	\$ 44.6	\$ 26.9	\$ 17.7	66%
Operating statistics:								
Crude oil gathered, MBbl/d	52.4	-	52.4	-	40.8	-	40.8	-
Plant natural gas inlet, MMcf/d (3) (4)	2,126.5	1,968.6	157.9	8%	2,092.0	2,094.3	(2.3)	0%
Gross NGL production, MBbl/d	142.3	123.4	18.9	15%	135.6	126.6	9.0	7%
Export volumes, MBbl/d	55.2	31.1	24.2	78%	47.1	40.8	6.3	16%
Natural gas sales, BBtu/d (4)	988.0	981.8	6.2	1%	930.8	924.4	6.4	1%
NGL sales, MBbl/d	303.9	282.0	21.9	8%	289.4	277.1	12.3	4%
Condensate sales, MBbl/d	3.7	3.6	0.1	4%	3.7	3.5	0.2	6%

- (1) Gross margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate the Partnership’s Operations” and “Non-GAAP Financial Measures.”
- (2) Operating margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate the Partnership’s Operations” and “Non-GAAP Financial Measures.”
- (3) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
- (4) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

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

The increase in revenues primarily reflects higher commodity sales volumes (\$77.4 million), higher realized prices on natural gas and condensate (\$60.9 million) and higher fee-based and other revenues (\$34.4 million).

The increase in consolidated gross margin was driven by increased volumes and higher natural gas prices in our Field Gathering and Processing segment and higher fractionation fees and increased exports activities in our Logistics and Marketing division. These favorable factors were partially offset by lower NGL prices in our Coastal Gathering and Processing segment. Higher operating expenses were driven by system expansions related to new operations in Field Gathering and Processing and of new growth projects in Logistics, costs associated with our Badlands growth and other higher labor and maintenance costs. See “—Results of Operations—By Reportable Segment” for additional information regarding changes in the components of gross and operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the Badlands acquisition, CBF Train 4, Phase I of the international export expansion project, other system expansions and other assets placed in service during the last twelve months.

General and administrative expenses increased, reflecting increased support for our expanding business operations.

Other operating expense in 2013 includes the Versado joint venture cost of repairs less amounts covered by insurance (\$3.7 million) related to a fire at the Saunders plant. Other operating expense in 2012 reflects losses due to Hurricane Isaac, which include the write-off upon closure of the Yscloskey joint interest processing plant and costs associated with the clean-up and repairs necessitated at our other Coastal Straddle plants.

The increase in interest expense primarily reflects higher borrowing levels to fund our business expansion (\$9.3 million), offset by lower effective interest rates (\$1.9 million) and higher interest capitalized on major capital projects (\$4.0 million).

The increase in equity earnings in the Partnership's investment in Gulf Coast Fractionators ("GCF"), which turned a profit in 2013 compared to a loss in 2012 due to a planned shutdown of operations associated with its capacity expansion during 2012.

In July 2013, we paid \$76.8 million plus accrued interest, which included a premium of \$4.1 million, per the terms of the note agreement to redeem the outstanding balance of the 11¼% Senior Notes due 2017 (the "11¼% Notes"). The redemption resulted in a \$7.4 million loss on debt redemption in the third quarter 2013, including the write-off of \$1.0 million of unamortized debt issue costs.

The increase in other income was attributable to the elimination of the contingent consideration associated with the Badlands acquisition (see Note 4 to the Consolidated Financial Statements). The elimination of the contingent liability reflects management's updated assessment, with only nine months remaining in the contingency period, that the Partnership will not meet the stipulated volumetric thresholds.

The increase in net income attributable to noncontrolling interests is primarily due to higher Partnership earnings, increased incentive distributions and higher income attributable to non-controlling interests. After adjusting for the impact of the IDRs, the weighted average percentages of the net income allocable to noncontrolling interest increased to 46.6% for the three months ended September 30, 2013 from 26.4% for the three months ended September 30, 2012. The increase in net income attributable to noncontrolling interests reflects higher earnings at the Partnership's CBF and VESCO joint ventures. The Partnership's Versado joint venture, which had lower earnings in 2013, was affected by operational issues, including a fire at the Saunders plant in September, which is still under repair.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

The increase in revenues reflects the impact of higher realized prices on natural gas and condensate (\$257.1 million), higher commodity volumes (\$136.3 million) and higher fee-based and other revenues (\$79.2 million), offset by lower realized prices on NGLs (\$434.8 million), especially during the first quarter of 2013.

The increase in consolidated gross margin for the nine months was driven by the same factors as discussed above for the three months, partially offset by the planned maintenance and inspection turnaround at CBF for the period from May through July 2013. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in the components of gross and operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to the Badlands acquisition, CBF Train 4, Phase I of the international export expansion project, other system expansions and other assets placed in service during the last twelve months.

General and administrative expenses increased, reflecting increased support for our expanding business operations.

Other operating expense in 2012 relates to the Yscloskey plant closure and Hurricane Isaac repair cost as discussed above.

The increase in interest expense primarily reflects higher borrowing levels to fund our business expansion (\$22.6 million) offset by lower effective interest rates (\$1.5 million) and higher interest capitalized on major capital projects (\$14.2 million).

The increase in equity earnings related to the Partnership's investment in GCF, which was profitable in 2013 compared to a loss in 2012 due to a planned shutdown of operations in 2012 related to an expansion of the facility.

The July 2013 11¼% Notes redemption noted above combined with the June 2013 6¾% Notes redemption resulted in \$14.7 million in losses on debt redemption for the nine months ended September 30, 2013.

The increase in other income was primarily attributable to the elimination of the contingent consideration liability associated with the Badlands acquisition as described above.

The decrease in net income attributable to noncontrolling interests is primarily due to lower Partnership earnings and increased incentive distributions. After adjusting for the impact of the IDRs, the weighted average percentages of the net income allocable to noncontrolling interest decreased to 34.3% for the nine months ended September 30, 2013 from 57.6% for the nine months ended September 30, 2012. Additionally, net income attributable to noncontrolling interests was \$5.4 million lower primarily due to a weaker price environment at the Partnership's Versado and VESCO joint ventures and impacted by operational issues, including the fire at the Saunders plant in September 2013, which is still under repair.

Results of Operations—By Reportable Segment

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

	Partnership					TRC Non-Partnership	Consolidated Operating Margin
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other		
	(In millions)						
Three Months Ended September 30,							
2013	\$ 70.6	\$ 21.1	\$ 70.5	\$ 32.5	\$ 4.8	\$ (0.1)	\$ 199.4
2012	53.8	18.0	50.4	25.4	14.0	0.6	162.2
Nine Months Ended September 30,							
2013	\$ 191.8	\$ 61.2	\$ 178.9	\$ 94.0	\$ 17.0	\$ (0.3)	\$ 542.6
2012	180.6	92.3	139.2	77.8	28.1	1.4	519.4

Results of Operations of the Partnership – By Reportable Segment

Gathering and Processing Segments

Field Gathering and Processing

	Three Months Ended September 30,		2013 vs. 2012		Nine Months Ended September 30,		2013 vs. 2012	
	2013	2012			2013	2012		
	(\$ in millions)							
Gross margin	\$ 113.5	\$ 84.0	\$ 29.5	35%	\$ 315.3	\$ 271.2	\$ 44.1	16%
Operating expenses	42.9	30.2	12.7	42%	123.5	90.6	32.9	36%
Operating margin	\$ 70.6	\$ 53.8	\$ 16.8	31%	\$ 191.8	\$ 180.6	\$ 11.2	6%
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Sand Hills	153.4	154.6	(1.2)	(1%)	156.0	143.7	12.3	9%
SAOU	163.9	126.0	37.9	30%	152.8	121.1	31.7	26%
North Texas System	310.9	246.5	64.4	26%	287.7	237.9	49.8	21%
Versado	159.3	159.2	0.1	0%	163.6	166.3	(2.7)	(2%)
Badlands	12.5	-	12.5	-	13.4	-	13.4	-
	<u>799.9</u>	<u>686.3</u>	<u>113.6</u>	<u>17%</u>	<u>773.5</u>	<u>669.0</u>	<u>104.5</u>	<u>16%</u>
Gross NGL production, MBbl/d								
Sand Hills	17.9	17.8	0.1	1%	17.6	16.8	0.8	5%
SAOU	23.7	19.5	4.2	22%	22.4	18.8	3.6	19%
North Texas System	31.8	26.6	5.2	20%	30.9	26.1	4.8	18%
Versado	19.6	19.0	0.6	3%	19.9	19.3	0.6	3%
Badlands	1.8	-	1.8	-	1.7	-	1.7	-
	<u>94.8</u>	<u>82.9</u>	<u>11.9</u>	<u>14%</u>	<u>92.5</u>	<u>81.0</u>	<u>11.5</u>	<u>14%</u>
Crude oil gathered, MBbl/d	<u>52.4</u>	<u>-</u>	<u>52.4</u>	<u>-</u>	<u>40.8</u>	<u>-</u>	<u>40.8</u>	<u>-</u>
Natural gas sales, BBtu/d (3)	404.4	333.5	70.9	21%	374.5	319.9	54.6	17%
NGL sales, MBbl/d	72.4	68.7	3.7	5%	70.1	67.1	3.0	5%
Condensate sales, MBbl/d	3.5	3.4	0.1	2%	3.4	3.3	0.1	2%
Average realized prices (4):								
Natural gas, \$/MMBtu	3.32	2.59	0.73	28%	3.46	2.40	1.06	44%
NGL, \$/gal	0.78	0.79	(0.01)	(1%)	0.73	0.90	(0.17)	(19%)
Condensate, \$/Bbl	101.93	86.82	15.11	17%	93.11	90.40	2.71	3%

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

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

The increase in gross margin was primarily due to higher overall throughput volumes with plant inlets up or flat in every business unit, despite operational issues. Gross margin also increased due to higher natural gas and condensate sales prices, which were partially offset by lower NGL sales prices. The increase in plant inlet volumes was largely attributable to new plant expansions that came on line at the end of 2012 and the first part of 2013 at Sand Hills and SAOU and new well connects, which increased available supply across each of our areas of operations, though throughput was somewhat constrained by operational issues. In the third quarter 2013, we commenced the fractionation of the temporary build of y-grade inventory that resulted from the CBF planned curtailment in the second quarter 2013. We expect to complete the fractionation of this additional y-grade inventory during the fourth quarter.

The increase in operating expenses was primarily due to the inclusion of Badlands operations in 2013 and additional compression related expenses due to increased volumes across our business and system expansions.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

The nine month results were impacted by the same factors as discussed above for the three months, with a larger negative impact from lower NGL prices.

Coastal Gathering and Processing

	Three Months Ended September 30,		2013 vs. 2012		Nine Months Ended September 30,		2013 vs. 2012	
	2013	2012			2013	2012		
	(\$ in millions)							
Gross margin	\$ 33.6	\$ 31.7	\$ 1.9	6%	\$ 96.1	\$ 127.2	\$ (31.1)	(24%)
Operating expenses	12.5	13.7	(1.2)	(9%)	34.9	34.9	-	0%
Operating margin	\$ 21.1	\$ 18.0	\$ 3.1	17%	\$ 61.2	\$ 92.3	\$ (31.1)	(34%)
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
LOU (4)	354.8	324.5	30.3	9%	338.0	245.0	93.0	38%
Coastal Straddles	466.1	607.7	(141.6)	(23%)	469.5	735.5	(266.0)	(36%)
VESCO	505.6	350.0	155.6	44%	510.9	444.8	66.1	15%
	<u>1,326.5</u>	<u>1,282.2</u>	<u>44.3</u>	<u>3%</u>	<u>1,318.5</u>	<u>1,425.3</u>	<u>(106.8)</u>	<u>(7%)</u>
Gross NGL production, MBbl/d								
LOU	11.3	8.9	2.4	27%	9.6	8.4	1.2	14%
Coastal Straddles	13.2	14.8	(1.6)	(11%)	13.2	16.0	(2.8)	(17%)
VESCO	23.0	16.9	6.1	36%	20.3	21.1	(0.8)	(4%)
	<u>47.4</u>	<u>40.6</u>	<u>6.8</u>	<u>17%</u>	<u>43.1</u>	<u>45.5</u>	<u>(2.4)</u>	<u>(5%)</u>
Natural gas sales, BBTu/d (3)	294.3	317.2	(22.9)	(7%)	285.0	304.8	(19.8)	(7%)
NGL sales, MBbl/d	43.2	38.4	4.8	13%	40.0	42.1	(2.1)	(5%)
Condensate sales, MBbl/d	0.3	0.2	0.1	38%	0.4	0.2	0.2	77%
Average realized prices:								
Natural gas, \$/MMBtu	3.61	2.87	0.74	26%	3.72	2.59	1.13	44%
NGL, \$/gal	0.80	0.85	(0.05)	(6%)	0.82	0.99	(0.17)	(17%)
Condensate, \$/Bbl	107.21	96.07	11.14	12%	107.19	107.17	0.02	0%

- (1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume during the quarter and the denominator is the number of calendar days during the quarter.
- (2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
- (3) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
- (4) Includes volumes from the Big Lake processing plant acquired in July 2012.

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

The increase in gross margin was primarily due to higher throughput volumes partially offset by lower NGL prices and less favorable frac spread. The increase in plant inlet volumes was largely attributable to the impact of Hurricane Isaac on production at the Coastal Straddle plants in the third quarter of 2012 and additional Big Lake volumes in 2013. This volume increase was partially offset by the 2013 decline in offshore and off-system supply volumes and the cessation of operations at Yscloskey and other third-party plant shutdowns.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

The decrease in gross margin was primarily due to lower NGL prices, less favorable frac spread and lower throughput volumes. The decrease in plant inlet volumes was largely attributable to the decline in offshore and off-system supply volumes, and the impact of the Yscloskey, Calumet and other third-party plant shutdowns. In addition, volumes were constrained by operational issues at VESCO and LOU. This volume decrease was partially offset by the addition of the Big Lake plant in the third quarter 2012 and the resumption of operations after Hurricane Isaac in 2012 at the Coastal Straddle plants. Operational issues at VESCO included the impact of damage to one of the two third-party pipelines that provide NGL takeaway capacity for VESCO which constrained NGL production until repairs were completed in June 2013.

Operating expenses were flat.

Logistics and Marketing Segments

Logistics Assets

	Three Months Ended September 30,		2013 vs. 2012		Nine Months Ended September 30,		2013 vs. 2012	
	2013	2012			2013	2012		
	(\$ in millions)							
Gross margin	\$ 100.1	\$ 74.5	\$ 25.6	34%	\$ 271.2	\$ 208.0	\$ 63.2	30%
Operating expenses	29.6	24.1	5.5	23%	92.3	68.8	23.5	34%
Operating margin	\$ 70.5	\$ 50.4	\$ 20.1	40%	\$ 178.9	\$ 139.2	\$ 39.7	29%
Operating statistics (1):								
Fractionation volumes, MBbl/d	316.4	293.3	23.1	8%	277.2	299.4	(22.2)	(7%)
LSNG treating volumes, MBbl/d	9.6	24.8	(15.2)	(61%)	18.2	23.7	(5.5)	(23%)
Benzene treating volumes, MBbl/d	8.1	19.8	(11.7)	(59%)	15.2	20.2	(5.0)	(25%)

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

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

Gross margin increased due to higher fractionation and export volumes. Fractionation volumes increased with the start up of Train 4 at CBF. Higher fractionation gross margin also includes the impact of higher fuel prices, which pass through to operating expenses. LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 55 MBbl/d for the third quarter 2013, compared to 31 MBbl/d for the same period last year. The increased volumes reflect an increase in ongoing LPG export activity, as well as low ethane propane cargoes loaded in connection with testing and commissioning of Phase I of our international export expansion project, which was placed in service in September. Export rates were also higher. Storage revenues were higher due to increased rates and new customers.

The increase in operating expenses primarily reflects increased fuel and power usage due to higher fractionation volumes and higher fuel and power prices (which have a corresponding impact on fractionating and treating revenues), expenses related to the commissioning and start-up of Train 4 at CBF, and increased maintenance costs, partially offset by higher system product gains.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

The nine month results were impacted by the same factors as discussed above for the three months. In addition, lower year-to-date fractionation volumes are due to the impact of turnaround related curtailments at CBF earlier in the year.

Marketing and Distribution

	Three Months Ended September 30,			Nine Months Ended September 30,				
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012		
	(\$ in millions)							
Gross margin	\$ 43.4	\$ 35.4	\$ 8.0	23%	\$ 125.5	\$ 106.2	\$ 19.3	18%
Operating expenses	10.9	10.0	0.9	9%	31.5	28.4	3.1	11%
Operating margin	\$ 32.5	\$ 25.4	\$ 7.1	28%	\$ 94.0	\$ 77.8	\$ 16.2	21%
Operating statistics (1):								
NGL sales, MBbl/d	306.7	289.4	17.3	6%	291.2	282.2	9.0	3%
Average realized prices:								
NGL realized price, \$/gal	0.88	0.88	-	0%	0.88	1.00	(0.12)	(12%)

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

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

Gross margin increased primarily due to higher LPG export activity, which benefited both the Logistics Assets and Marketing and Distribution segments (see Logistics Assets) and higher truck and barge utilization.

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

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

The nine month results were impacted by the same factors as discussed above for the three months, plus the negative impact of related lower NGL prices.

Other

	Three Months Ended September 30,			Nine Months Ended September 30,				
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012		
	(In millions)							
Gross margin	\$ 4.8	\$ 14.0	\$ (9.2)	\$ 17.0	\$ 28.1	\$ (11.1)		
Operating margin	\$ 4.8	\$ 14.0	\$ (9.2)	\$ 17.0	\$ 28.1	\$ (11.1)		

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

The primary purpose of the Partnership's commodity risk management activities is to manage its exposure to commodity price risk and reduce volatility in its operating cash flow due to fluctuations in commodity prices. The Partnership has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent of proceeds or liquids processing arrangements by entering into derivative instruments.

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

	Three Months Ended September 30,		2013 vs. 2012	Nine Months Ended September 30,		2013 vs. 2012
	2013	2012		2013	2012	
	(In millions)					
Natural gas	\$ 3.8	\$ 8.0	\$ (4.2)	\$ 8.1	\$ 26.9	\$ (18.8)
NGL	3.3	6.0	(2.7)	11.3	3.5	7.8
Crude oil	(2.3)	-	(2.3)	(2.4)	(2.3)	(0.1)
	<u>\$ 4.8</u>	<u>\$ 14.0</u>	<u>\$ (9.2)</u>	<u>\$ 17.0</u>	<u>\$ 28.1</u>	<u>\$ (11.1)</u>

Because we are essentially forward selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices.

Our Liquidity and Capital Resources

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

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all of the outstanding IDRs; and
- 12,945,659 of the 108,458,496 outstanding common units of the Partnership, representing an 11.9% limited partnership interest.

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

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

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

As of October 28, 2013, our liquidity consisted of the following:

	October 28, 2013
	(In millions)
Cash on hand	\$ 7.0
Total availability under TRC's credit facility	150.0
Less: Outstanding borrowings under TRC's credit facility	(77.0)
Less: Outstanding letters of credit outstanding under TRC's credit facility	-
Total liquidity	\$ 80.0

We have sufficient liquidity to satisfy over the next 12 years the \$63.1 million tax liability we incurred as a result of our sales of assets to the Partnership.

Subsequent Event

On October 21, 2013, the Partnership announced that the board of directors of its general partner declared a quarterly distribution for the three months ended September 30, 2013 of \$0.7325 per common unit, or an annual rate of \$2.93 per common unit. This distribution will be paid on November 14, 2013. Based on these current distribution rates, we will receive approximate distributions in future quarters and years of:

- \$9.5 million or \$37.9 million annually based on our common unit ownership in the Partnership;
- \$26.9 million or \$107.7 million annually based on our IDRs; and
- \$2.2 million or \$8.7 million annually based on our 2% general partner interests.

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

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

Three Months Ended	Date Paid or to be Paid	Total Dividend Declared	Amount of Dividend Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
(In millions, except per share amounts)					
September 30, 2013	November 15, 2013	\$ 24.1	\$ 23.7	\$ 0.4	\$ 0.57000
June 30, 2013	August 15, 2013	22.5	22.1	0.4	0.53250
March 31, 2013	May 16, 2013	21.0	20.6	0.4	0.49500
December 31, 2012	February 15, 2013	19.4	19.0	0.4	0.45750

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

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

As of October 28, 2013, the Partnership's liquidity consisted of the following:

	October 28, 2013
	(In millions)
Cash on hand	\$ 127.0
Total availability under the TRP Revolver	1,200.0
Total availability under the Securitization Facility	<u>200.0</u>
	1,527.0
Less: Outstanding borrowings under the TRP Revolver	(418.0)
Outstanding borrowings under the Securitization Facility	(200.0)
Outstanding letters of credit under the TRP Revolver	(49.4)
Total liquidity	<u>\$ 859.6</u>

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

In April 2013, the Partnership filed with the SEC a universal shelf registration statement (the April 2013 Shelf), which provides it with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and its capital needs. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the nine months ended September 30, 2013.

In July 2013, the Partnership filed with the SEC a universal shelf registration statement (the July 2013 Shelf), that allows it to issue up to an aggregate of \$800 million of debt or equity securities. The July 2013 Shelf expires in August 2016. The Partnership has the ability to sell additional common units up to an aggregate amount of \$713.9 million under the July 2013 Shelf.

Risk Management

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

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

The Partnership's risk management position has moved from a net asset position of \$22.2 million at December 31 2012 to a net asset position of \$7.7 million at September 30, 2013. Aggregate forward prices for commodities are below the fixed prices the Partnership currently expects to receive on those derivative contracts, creating this net asset position. Consequently, the Partnership's expected future receipts on derivative contracts are greater than its expected future payments. The Partnership accounts for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

Working Capital

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

For the nine months ended September 30, 2013, the Partnership's working capital increased \$79.7 million, primarily due to an increase of inventory in advance of the start-up of the Partnership's international export project, which was commissioned in September, increased materials and supply inventory required for expansion of the Badlands operations and a decrease in affiliate payables due to timing of reimbursements between the Partnership and us. The impact of higher accounts receivable for the Partnership's expanding LPG export activity was largely offset by increased gas plant producer settlement payables due to higher natural gas prices.

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

A significant portion of the Partnership's capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While the Partnership's credit ratings have improved over time, these letters of credit reflect its non-investment grade status, as assigned to us by Moody's Investors Service, Inc. and Standard & Poor's Corporation, and counterparties' views of the Partnership's financial condition and ability to satisfy its performance obligations, as well as commodity prices and other factors. As of September 30, 2013, the Partnership had \$50.0 million in letters of credit outstanding.

Cash Flow

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

Nine Months Ended September 30, 2013	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
		(In millions)	
Net cash provided by (used in):			
Operating activities	\$ 258.1	\$ 276.3	\$ (18.2)
Investing activities	(737.6)	(737.6)	-
Financing activities	486.9	467.4	19.5
Nine Months Ended September 30, 2012			
Net cash provided by (used in):			
Operating activities	\$ 290.2	\$ 315.5	\$ (25.3)
Investing activities	(403.8)	(403.5)	(0.3)
Financing activities	88.5	121.3	(32.8)

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.

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:

	Nine Months Ended September 30,					
	2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership
	(In millions)					
Cash flows from operating activities:						
Cash received from customers	\$ 4,393.6	\$ 4,393.5	\$ 0.1	\$ 4,501.5	\$ 4,502.0	\$ (0.5)
Cash received from (paid to) derivative counterparties	16.9	16.9	-	32.7	32.7	-
Cash outlays for:						
Product purchases	(3,668.9)	(3,668.9)	-	(3,808.8)	(3,808.2)	(0.6)
Operating expenses	(276.4)	(276.4)	-	(218.8)	(218.8)	-
General and administrative expenses	(110.2)	(114.7)	4.5	(109.4)	(110.5)	1.1
Cash distributions from equity investment (1)	10.1	10.1	-	-	-	-
Interest paid, net of amounts capitalized (2)	(83.0)	(81.0)	(2.0)	(82.9)	(80.4)	(2.5)
Income taxes paid	(23.1)	(2.3)	(20.8)	(24.4)	(2.1)	(22.3)
Other cash receipts (payments)	(0.9)	(0.9)	-	0.3	0.8	(0.5)
Net cash provided by operating activities	\$ 258.1	\$ 276.3	\$ (18.2)	\$ 290.2	\$ 315.5	\$ (25.3)

(1) Excludes \$1.9 million and \$2.3 million included in investing activities for the nine months ended September 30, 2013 and 2012 related to distributions from GCF that exceeded cumulative equity earnings.

(2) Net of capitalized interest paid of \$22.6 million and \$8.5 million included in investing activities for the nine months ended September 30, 2013 and 2012.

Despite higher reported accrual based revenues for 2013 versus 2012, cash collections from customers were lower for 2013, reflecting higher export receivables outstanding at September 30, 2013 and lower proceeds from derivative settlements. Cash paid for purchases was also impacted by lower liquid prices, partially offset by higher natural gas prices paid to producers.

Cash Flow from Investing Activities - Partnership

The increase in net cash used in investing activities was primarily due to an increase in current capital expansion projects of \$336.9 million and the purchase of material and supplies of \$35.3 million related to our Badlands expansion, partially offset by a decrease in business acquisition of \$25.8 million and the absence of capital calls in 2013 at GCF (\$16.8 million).

Cash Flow from Financing Activities - Partnership

The increase in net cash provided by financing activities was primarily due to an increase in long-term debt net borrowings of \$207.8 million, and an increase in proceeds from the issuance of common units of \$211.9 million, partially offset by an increase in distributions to owners of \$79.9 million.

Our primary financing activities during the nine months ended September 30, 2013 were:

- \$220.0 million related to net repayments under credit facility;
- \$377.4 million from the sale of common units under the 2012 and 2013 EDAs;
- \$7.9 million related general partner contributions to maintain 2% general partner ownership;
- \$168.0 million of net borrowings under the Securitization Facility;
- \$618.1 million of new debt from the issuance of 4¼% Notes;
- \$106.4 million related to the redemption of \$100 million face value of 6¾% Senior Notes; and
- \$76.8 million related to the redemption of \$72.7 million face value of 11¼% Senior Notes.

Cash Flow Financing Activities - Non-Partnership

Financing activities provided a net source of cash compared to a use in 2012 primarily due to the purchase in 2012 of Partnership units for \$47.0 million and an increase in distributions received of \$33.3 million, partially offset by an increase in payments on the TRC Revolver of \$12.0 million and an increase in dividends paid of \$16.9 million.

Distributions from the Partnership and Dividends of TRC

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

For the Three Months Ended	Date Paid or to be Paid	Cash Distribution Per Limited Partner Unit	Cash Distributions				Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
			Limited Partner Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (1)		
(In millions, except per unit amounts)								
September 30, 2013	November 14, 2013	\$ 0.7325	\$ 9.5	\$ 2.2	\$ 26.9	\$ 38.6	\$ 0.57000	\$ 24.1
June 30, 2013	August 14, 2013	0.7150	9.3	2.0	24.6	35.9	0.53250	22.5
March 31, 2013	May 15, 2013	0.6975	9.0	1.9	22.1	33.0	0.49500	21.0
December 31, 2012	February 14, 2013	0.6800	8.8	1.8	20.1	30.7	0.45750	19.4

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

Capital Requirements

The Partnership's capital requirements relate to capital expenditures, which are classified as expansion expenditures, maintenance expenditures or business acquisitions. Expansion capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues, and fund acquisitions of businesses or assets. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life, and expenditures to remain in compliance with environmental laws and regulations.

	Nine Months Ended September 30,					
	2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
(In millions)						
Capital expenditures:						
Business acquisitions, net of cash acquired	\$ -	\$ -	\$ -	\$ 25.8	\$ 25.8	\$ -
Expansion (1)	666.6	666.6	-	326.1	326.0	0.1
Maintenance	60.5	60.5	-	48.3	48.0	0.3
Gross additions to property, plant and equipment	727.1	727.1	-	400.2	399.8	0.4
Transfers from materials and supplies to property, plant and equipment	(15.1)	(15.1)	-	-	-	-
Change in capital project payables and accruals	(3.8)	(3.8)	-	(9.3)	(9.2)	(0.1)
Cash outlays for capital projects	\$ 708.2	\$ 708.2	\$ -	\$ 390.9	\$ 390.6	\$ 0.3

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

The Partnership estimates that its total growth capital expenditures for 2013 will be approximately \$900 million on a gross basis, and maintenance capital expenditures net to the Partnership's interest will be approximately \$80 million. Given the Partnership's objective of growth through acquisitions, expansions of existing assets and other internal growth projects, the Partnership anticipates that over time they will invest significant amounts of capital to grow and acquire assets. The Partnership's future expansion capital expenditures may vary significantly based on investment opportunities. The Partnership expects to fund future capital expenditures with funds generated from its operations, borrowings under the TRP Revolver and the Securitization Facility and proceeds from issuances of additional equity and debt offerings.

Critical Accounting Policies and Estimates

The Partnership and our critical accounting policies and estimates are set forth in Part II, “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our Annual Report. During the nine months ended September 30, 2013, the Partnership established policies related to the amortization and useful lives of the intangible assets related to the Badlands acquisition.

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

Off-Balance Sheet Arrangements

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

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

Our exposure to market risk is largely derivative of the Partnership’s exposure to market risk. The Partnership’s principal market risks are its exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by its customers. Neither the Partnership nor we use risk sensitive instruments for trading purposes.

Commodity Price Risk

A significant portion of the Partnership’s revenues are derived from percent-of-proceeds contracts under which it receives a portion of the natural gas and/or NGLs or equity volumes as payment for services. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond the Partnership’s control. The Partnership monitors these risks and enters into hedging transactions designed to mitigate the impact of commodity price fluctuations on its business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of the commodity risk management activities is to manage the exposure to commodity price risk and reduce volatility in the Partnership’s operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of the Partnership’s cash flows, as of September 30, 2013, the Partnership has hedged the commodity prices associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations, as well as in the LOU portion of the Coastal Gathering and Processing Operations, that results from percent of proceeds processing arrangements. The Partnership hedges a higher percentage of its expected equity volumes in the current year compared to future years, in which it hedges incrementally lower percentages of expected equity volumes. With swaps, the Partnership typically receives an agreed fixed price for a specified notional quantity of natural gas or NGLs and it pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than its actual equity volumes, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership may buy calls in connection with swap positions to create a price floor with upside. The Partnership intends to continue to manage its exposure to commodity prices in the future by entering into similar derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

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

These commodity price-hedging transactions are typically documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. The principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. The Partnership’s payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas and NGL prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing its senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its senior secured lenders. Absent federal regulations resulting from the Dodd-Frank Wall Street Reform and Consumer Protection Act, and as long as this first priority lien is in effect, the Partnership expects to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if a counterparty’s exposure to the Partnership’s credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in the Partnership’s creditworthiness. A purchased put (or floor) transaction does not expose the Partnership’s counterparties to credit risk, as the Partnership has no obligation to make future payments beyond the premium paid to enter into the transaction, however, the Partnership is exposed to the risk of default by the counterparty, which is the risk that the counterparty will not honor its obligation under the put transaction.

For all periods presented, the Partnership has entered into hedging arrangements for a portion of its forecasted equity volumes. During the three months ended September 30, 2013, and 2012, our operating revenues were increased by net hedge adjustments on commodity derivative contracts of \$4.8 million and \$13.2 million. During the nine months ended September 30, 2013, and 2012, our operating revenues were increased by net hedge adjustments on commodity derivative contracts of \$17.0 million and \$25.6 million. The net hedge adjustments that impact our consolidated revenues (but do not affect the Partnership's revenues) include amortization of OCI related to hedges terminated and re-assigned upon the Partnership's acquisition of Versado in 2010, as well as OCI related to terminations of commodity derivatives in July 2008.

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

Natural Gas							
Instrument Type	Index	Price \$/MMBtu	MMBtu/d				Fair Value (In millions)
			2013	2014	2015	2016	
Swap	IF-WAHA	4.45	18,354				\$ 1.6
Swap	IF-WAHA	3.86		14,780			0.5
Swap	IF-WAHA	4.05			8,736		0.4
Swap	IF-WAHA	4.25				4,436	0.3
Total Swaps			18,354	14,780	8,736	4,436	
Swap	IF-PB	4.50	14,871				1.4
Swap	IF-PB	3.80		11,966			0.3
Swap	IF-PB	4.02			7,076		0.3
Swap	IF-PB	4.22				3,608	0.3
Total Swaps			14,871	11,966	7,076	3,608	
Swap	IF-NGPL MC	4.14	7,865				0.5
Swap	IF-NGPL MC	3.58		6,304			(0.2)
Swap	IF-NGPL MC	3.88			3,739		0.2
Swap	IF-NGPL MC	4.13				1,956	0.4
Total Swaps			7,865	6,304	3,739	1,956	
Total			41,090	33,050	19,551	10,000	\$ 6.0

NGL						
Instrument Type	Index	Price \$/Gal	Bbl/d		Fair Value (In millions)	
			2013	2014		
Swap	OPIS-MB	1.05	5,650		\$ 2.8	
Swap	OPIS-MB	1.21		1,000	3.3	
Total			5,650	1,000	\$ 6.1	

Instrument Type	Index	Condensate		Fair Value (In millions)	
		Price \$/Bbl	Bbl/d		
			2013		2014
Swap	NY-WTI	93.23	2,045	\$ (1.6)	
Swap	NY-WTI	89.80		1,450 (2.8)	
Total			2,045	1,450 (4.4)	

These contracts may expose the Partnership to the risk of financial loss in certain circumstances. Generally, the Partnership's hedging arrangements provide protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which they have been hedged, the Partnership will receive less revenue on the hedged volumes than it would receive in the absence of hedges (other than with respect to purchased calls).

The Partnership accounts for the fair value of its financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. The Partnership values its derivative contracts utilizing a discounted cash flow model for swaps and a standard option-pricing model for options, based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which the Partnership is unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 13 to the "Consolidated Financial Statements" in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRC Revolver. The Partnership is exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under its TRP Revolver and its Securitization Facility. As of September 30, 2013, neither the Partnership nor we have any interest rate hedges. However, the Partnership or we may in the future enter into interest rate hedges intended to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRC Revolver, the TRP Revolver and its Securitization Facility will also increase. As of September 30, 2013, the Partnership had \$568.0 million in variable rate borrowings under its TRP Revolver and its Securitization Facility and we had variable rate borrowings of \$70.0 million under our TRC Revolver. A hypothetical change of 100 basis points in the interest rate of variable rate debt would impact the Partnership's annual interest expense by \$5.7 million and the TRC Non-Partnership annual interest expense by \$0.7 million.

Counterparty Credit Risk

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

As of September 30, 2013 affiliates of Bank of America Merrill Lynch ("BAML"), Barclays PLC ("Barclays"), Wells Fargo Bank N.A. ("Wells Fargo") and Natixis Securities Americas LLC ("Natixis") accounted for 30%, 24%, 16% and 14% of the Partnership's counterparty credit exposure related to commodity derivative instruments. BAML, Barclays, Wells Fargo and Natixis are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody's Investors Service, Inc. and Standard & Poor's Corporation.

Customer Credit Risk

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

The Partnership has an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of the Partnership's third-party accounts receivable, annual operating income would decrease by \$5.0 million in the year of the assessment.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered by this Quarterly Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of September 30, 2013, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered by this Quarterly Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the three months ended September 30, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 14 – Commitments and Contingencies, included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

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

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

Not applicable.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Number	Description
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.3	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.4	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.5	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.6	Amendment No. 1, dated May 13, 2008, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.7	Amendment No. 2, dated May 25, 2012, to the First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 25, 2012 (File No. 001-33303)).
3.8	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.9	Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
3.10	Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.9 to Targa Resources Corp.'s Annual Report on Form 10-K filed February 28, 2011 (File No. 001-33303)).
3.11	Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

[32.2**](#) Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.INS* XBRL Instance Document

101.SCH* XBRL Taxonomy Extension Schema Document

101.CAL* XBRL Taxonomy Extension Calculation Linkbase Document

101.DEF* XBRL Taxonomy Extension Definition Linkbase Document

101.LAB* XBRL Taxonomy Extension Label Linkbase Document

101.PRE* XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

** Furnished herewith

SIGNATURES

Pursuant to the requirements of 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: November 4, 2013

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

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

I, Joe Bob Perkins, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Corp. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 4, 2013

By: /s/ Joe Bob Perkins

Name: Joe Bob Perkins

Title: Chief Executive Officer of Targa Resources Corp.

(Principal Executive Officer)

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

I, Matthew J. Meloy, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Corp. (the “registrant”);
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 4, 2013

By: /s/ Matthew J. Meloy

Name: Matthew J. Meloy

Title: Senior Vice President, Chief Financial Officer and Treasurer of Targa Resources Corp.
(Principal Financial Officer)

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

In connection with the Quarterly Report on Form 10-Q of Targa Resources Corp., for the three months ended September 30, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Joe Bob Perkins, as Chief Executive Officer of Targa Resources Corp., hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Targa Resources Corp.

By: /s/ Joe Bob Perkins

Name: Joe Bob Perkins

Title: Chief Executive Officer of Targa Resources Corp.

Date: November 4, 2013

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

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

In connection with the Quarterly Report on Form 10-Q of Targa Resources Corp. for the three months ended September 30, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Matthew J. Meloy, as Chief Financial Officer of Targa Resources Corp., hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Targa Resources Corp.

By: /s/ Matthew J. Meloy

Name: Matthew J. Meloy

Title: Senior Vice President, Chief Financial Officer and Treasurer of
Targa Resources Corp.

Date: November 4, 2013

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