Targa Resources Corp.
Form 10-Q
August 03, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2016

Or

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

For the transition period from _____ to _____

Commission File Number: 001-34991

TARGA RESOURCES CORP.

(Exact name of registrant as specified in its charter)

Delaware	20-3701075
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1000 Louisiana St, Suite 4300, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 584-1000

(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T

(§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

As of July 29, 2016, there were 166,630,466 shares of the registrant's common stock, $0.001 par value, outstanding.

PART I—FINANCIAL INFORMATION

1

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, including Targa Resources Partners LP ("the Partnership" or "TRP"), "we," "us," "Targa," "TRC," or the "Company") reports, filings and other public announcements may from time to tin 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 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 following risks and uncertainties:

- the timing and extent of changes in natural gas, natural gas liquids ("NGL"), crude oil and other commodity prices, interest rates and demand for our services;
- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and NGL supplies to our logistics and marketing facilities and our success in connecting our facilities to transportation services and markets;
- our ability to access the capital markets, which will depend on general market conditions and the credit ratings for the Partnership's and our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity price risks;
- the level of creditworthiness of counterparties to various transactions with us;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- 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 in our Annual Report on Form 10-K for the year ended December 31, 2015 ("Annual Report"), this Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 (the "Quarterly 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.

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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
Bcf	Billion cubic feet
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
MMgal	Million U.S. gallons
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 Offered 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
NG-NYMEX	NYMEX, Natural Gas

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.

CONSOLIDATED BALANCE SHEETS

	June 30, 2016 (Unaudited)	December 31, 2015
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 170.9	$ 140.2
Trade receivables, net of allowances of $0.1 million as of June 30, 2016 and $0.1 million as of December 31, 2015	490.1	515.8
Inventories	111.0	141.0
Assets from risk management activities	41.4	92.2
Other current assets	43.3	30.8
Total current assets	856.7	920.0
Property, plant and equipment	12,229.4	11,935.1
Accumulated depreciation	(2,526.9)	(2,232.4)
Property, plant and equipment, net	9,702.5	9,702.7
Intangible assets, net	1,726.0	1,810.1
Goodwill, net	393.0	417.0
Long-term assets from risk management activities	13.6	34.9
Investments in unconsolidated affiliates	250.2	258.9
Other long-term assets	58.1	67.4
Total assets	$ 13,000.1	$ 13,211.0
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 697.7	$ 657.1
Liabilities from risk management activities	14.9	5.2
Accounts receivable securitization facility	225.0	219.3
Total current liabilities	937.6	881.6
Long-term debt	4,778.3	5,718.8
Long-term liabilities from risk management activities	19.7	2.4
Deferred income taxes, net	1,083.0	177.8
Other long-term liabilities	164.5	180.2
Contingencies (see Note 17)		
Series A Preferred 9.5% Stock, $1,000 per share liquidation preference, (1,200,000 shares authorized, issued and outstanding 965,100 shares)	179.9	—

Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300,000,000 shares authorized)	0.2	0.1
Issued / Outstanding		
June 30, 2016: 166,302,062 / 165,822,818		
December 31, 2015: 56,446,573 / 56,020,266		
Preferred stock ($0.001 par value, after designation of Series A Preferred Stock (above) 98,800,000 shares authorized, no shares issued and outstanding)	—	—
Additional paid-in capital	5,371.3	1,457.4
Receivables from common stock issuances	(36.0)	—
Retained earnings (deficit)	(25.9)	26.9
Accumulated other comprehensive income (loss)	(5.7)	5.7
Treasury stock, at cost (479,244 shares as of June 30, 2016 and 426,307 as of December 31, 2015)	(29.1)	(28.7)
Total Targa Resources Corp. stockholders' equity	5,274.8	1,461.4
Noncontrolling interests in subsidiaries	562.3	4,788.8
Total owners' equity	5,837.1	6,250.2
Total liabilities, Series A Preferred Stock and owners' equity	$ 13,000.1	$ 13,211.0

See notes to consolidated financial statements

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(Unaudited)			
	(In millions, except per share amounts)			
Revenues				
Sales of commodities	$1,312.9	$1,396.1	$2,484.0	$2,798.3
Fees from midstream services	270.7	303.3	542.0	580.8
Total revenues	1,583.6	1,699.4	3,026.0	3,379.1
Costs and expenses:				
Product purchases	1,145.2	1,228.1	2,156.2	2,486.6
Operating expenses	138.9	145.8	271.0	266.9
Depreciation and amortization expenses	186.1	163.9	379.6	282.5
General and administrative expenses	47.0	49.2	92.2	91.7
Goodwill impairment	—	—	24.0	—
Other operating (income) expense	0.1	—	1.1	0.6
Income from operations	66.3	112.4	101.9	250.8
Other income (expense):				
Interest expense, net	(71.4)	(67.6)	(124.3)	(121.7)
Equity earnings (loss)	(4.4)	(1.5)	(9.2)	0.5
Gain (loss) from financing activities	(3.3)	(3.8)	21.4	(12.9)
Other	(0.1)	(0.9)	(0.2)	(26.9)
Income (loss) before income taxes	(12.9)	38.6	(10.4)	89.8
Income tax (expense) benefit	(1.7)	(14.8)	(4.8)	(30.1)
Net income (loss)	(14.6)	23.8	(15.2)	59.7
Less: Net income attributable to noncontrolling interests	8.6	8.6	10.7	41.1
Net income (loss) attributable to Targa Resources Corp.	(23.2)	15.2	(25.9)	18.6
Dividends on Series A preferred stock	22.9	—	26.7	—
Deemed dividends on Series A preferred stock	6.5	—	6.5	—
Net income (loss) attributable to common shareholders	$(52.6)	$15.2	$(59.1)	$18.6
Net income (loss) per common share - basic	$(0.33)	$0.27	$(0.44)	$0.37
Net income (loss) per common share - diluted	$(0.33)	$0.27	$(0.44)	$0.36
Weighted average shares outstanding - basic	161.6	55.9	134.1	50.9
Weighted average shares outstanding - diluted	161.6	56.1	134.1	51.0

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30,					
	2016			2015		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income (loss) attributable to Targa Resources Corp.			$ (23.2)			$ 15.2
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$ (60.2)	$ 22.9	(37.3)	$ (0.5)	$ 0.2	(0.3)
Settlements reclassified to revenues	(18.3)	6.9	(11.4)	(2.4)	0.9	(1.5)
Other comprehensive income (loss) attributable to Targa Resources Corp.	(78.5)	29.8	(48.7)	(2.9)	1.1	(1.8)
Comprehensive income attributable to Targa Resources Corp.			(71.9)			13.4
Net income (loss) attributable to noncontrolling interests			8.6			8.6
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	—	—	—	(3.1)	—	(3.1)
Settlements reclassified to revenues	—	—	—	(19.0)	—	(19.0)
Other comprehensive income (loss) attributable to noncontrolling interests	—	—	—	(22.1)	—	(22.1)
Comprehensive income (loss) attributable to noncontrolling interests			8.6			(13.5)
Total						
Net income (loss)			(14.6)			23.8
Other comprehensive income (loss)						
Commodity hedging contracts:						
Change in fair value	(60.2)	22.9	(37.3)	(3.6)	0.2	(3.4)
Settlements reclassified to revenues	(18.3)	6.9	(11.4)	(21.4)	0.9	(20.5)
Other comprehensive income (loss)	$ (78.5)	$ 29.8	(48.7)	$ (25.0)	$ 1.1	(23.9)
Total comprehensive income (loss)			$ (63.3)			$ (0.1)

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Six Months Ended June 30,					
	2016			2015		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited)					
	(In millions)					
Net income (loss) attributable to Targa Resources Corp.			$ (25.9)			$ 18.6
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$ (77.1)	$ 29.4	(47.7)	$ 2.0	$ (0.6)	1.4
Settlements reclassified to revenues	(31.3)	11.9	(19.4)	(4.1)	1.4	(2.7)
Other comprehensive income (loss) attributable to Targa Resources Corp.	(108.4)	41.3	(67.1)	(2.1)	0.8	(1.3)
Comprehensive income attributable to Targa Resources Corp.			(93.0)			17.3
Net income (loss) attributable to noncontrolling interests			10.7			41.1
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	23.6	—	23.6	25.0	—	25.0
Settlements reclassified to revenues	(11.1)	—	(11.1)	(30.8)	—	(30.8)
Other comprehensive income (loss) attributable to noncontrolling interests	12.5	—	12.5	(5.8)	—	(5.8)
Comprehensive income (loss) attributable to noncontrolling interests			23.2			35.3
Total						
Net income (loss)			(15.2)			59.7
Other comprehensive income (loss)						
Commodity hedging contracts:						
Change in fair value	(53.5)	29.4	(24.1)	27.0	(0.6)	26.4
Settlements reclassified to revenues	(42.4)	11.9	(30.5)	(34.9)	1.4	(33.5)
Other comprehensive income (loss)	$ (95.9)	$ 41.3	(54.6)	$ (7.9)	$ 0.8	(7.1)
Total comprehensive income (loss)			$ (69.8)			$ 52.6

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

	Common Stock		Additional Paid in	Retained Earnings (Accumulated	Accumulated Other Comprehensive Income	Treasury Shares		Noncontrolling	Total Owner's	Series A Preferred
	Shares	Amount	Capital	Deficit)	(Loss)	Shares	Amount	Interests	Equity	Stock
	(Unaudited)									
	(In millions, except shares in thousands)									
Balance, December 31, 2015	56,020	$ 0.1	$ 1,457.4	$ 26.9	$ 5.7	426	$ (28.7)	$ 4,788.8	$ 6,250.2	$ —
Compensation on equity grants	—	—	13.0	—	—	—	—	2.2	15.2	—
Distribution equivalent rights	—	—	(4.9)	—	—	—	—	(0.2)	(5.1)	—
Shares issued under compensation program	224	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(54)	—	—	—	—	54	(0.4)	(0.1)	(0.5)	—
Proceeds from common stock issuances	5,106	—	215.1	—	—	—	—	—	215.1	—
Receivables from common stock offerings	—	—	(36.0)	—	—	—	—	—	(36.0)	—
Issuance of Series A preferred and detachable warrants	—	—	796.8	—	—	—	—	—	796.8	179.9
Series A preferred stock dividends	—	—	—	(3.8)	—	—	—	—	(3.8)	—
Series A preferred stock dividends in excess of retained earnings	—	—	(22.9)	—	—	—	—	—	(22.9)	—
	—	—	(6.5)	—	—	—	—	—	(6.5)	—

Series A preferred stock deemed dividends										
Common stock dividends	—	—	—	(23.1)	—	—	—	—	(23.1)	—
Common stock dividends in excess of retained earnings	—	—	(174.2)	—	—	—	—	—	(174.2)	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(151.0)	(151.0)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	19.1	19.1	—
Acquisition of TRP noncontrolling common interests, net of acquisition costs	104,526	0.1	3,097.5	—	55.7	—	—	(4,119.7)	(966.4)	—
Other comprehensive income (loss)	—	—	—	—	(67.1)	—	—	12.5	(54.6)	—
Net income (loss)	—	—	—	(25.9)	—	—	—	10.7	(15.2)	—
Balance, June 30, 2016	165,822	$ 0.2	$ 5,335.3	$ (25.9)	$ (5.7)	480	$ (29.1)	$ 562.3	$ 5,837.1	$ 179.9

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Common Stock		Additional Paid in	Retained Earnings (Accumulated	Accumulated Other Comprehensive Income	Treasury Shares		Noncontrolling	Total Owner's
	Shares	Amount	Capital	Deficit)	(Loss)	Shares	Amount	Interests	Equity
	(Unaudited)								
	(In millions, except shares in thousands)								
Balance, December 31, 2014	42,143	$ —	$ 164.9	$ 25.5	$ 4.8	389	$ (25.4)	$ 2,369.7	$ 2,539.5
Compensation on equity grants	—	—	3.5	—	—	—	—	8.9	12.4
Distribution equivalent rights	—	—	(0.3)	—	—	—	—	(0.7)	(1.0)
Shares issued under compensation program	47	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(23)	—	—	—	—	23	(2.1)	(2.1)	(4.2)
Sale of Partnership limited partner interests	—	—	—	—	—	—	—	293.4	293.4
Proceeds from common stock issuances	3,738	—	336.6	—	—	—	—	—	336.6
Impact of Partnership equity transactions	—	—	56.5	—	—	—	—	(56.5)	—
Dividends	—	—	—	(28.7)	—	—	—	—	(28.7)
Dividends in excess of retained earnings	—	—	(50.2)	—	—	—	—	—	(50.2)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(226.9)	(226.9)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	5.9	5.9
Noncontrolling interests in acquired subsidiaries	—	—	—	—	—	—	—	113.4	113.4
Common stock issued in ATLS merger	10,126	0.1	1,013.6	—	—	—	—	—	1,013.7
Partnership units issued in APL merger	—	—	—	—	—	—	—	2,435.7	2,435.7
Other comprehensive income (loss)	—	—	—	—	(1.3)	—	—	(5.8)	(7.1)
Net income	—	—	—	18.6	—	—	—	41.1	59.7

Balance, June 30, 2015	56,031	$ 0.1	$ 1,524.6	$ 15.4	$ 3.5	412	$ (27.5)	$ 4,976.1	$ 6,492.2

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2016	2015
	(Unaudited)	
	(In millions)	
Cash flows from operating activities		
Net income (loss)	$(15.2)	$59.7
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	8.2	7.2
Compensation on equity grants	15.2	12.4
Depreciation and amortization expense	379.6	282.5
Goodwill impairment	24.0	—
Accretion of asset retirement obligations	2.3	2.7
Change in redemption value of mandatorily redeemable preferred interest	(14.6)	—
Deferred income tax expense (benefit)	4.8	18.5
Equity (earnings) loss of unconsolidated affiliates	9.2	(0.5)
Distributions of earnings received from unconsolidated affiliates	—	6.9
Risk management activities	3.2	31.5
(Gain) loss on sale or disposition of assets	0.9	(0.2)
(Gain) loss from financing activities	(21.4)	12.9
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	19.6	131.7
Inventories	12.4	57.9
Accounts payable and other liabilities	29.3	(139.0)
Net cash provided by operating activities	457.5	484.2
Cash flows from investing activities		
Outlays for property, plant and equipment	(307.7)	(436.2)
Outlays for business acquisitions, net of cash acquired	—	(1,574.4)
Return of capital from unconsolidated affiliates	3.9	0.1
Other, net	(1.4)	(1.3)
Net cash used in investing activities	(305.2)	(2,011.8)
Cash flows from financing activities		
Debt obligations:		
Proceeds from borrowings under credit facilities	1,067.0	1,824.0
Repayments of credit facilities	(1,457.0)	(588.0)
Proceeds from accounts receivable securitization facility	121.4	253.4
Repayments of accounts receivable securitization facility	(115.7)	(312.0)
Proceeds from issuance of senior notes and term loan	—	1,522.5
Open market purchases of senior notes	(534.3)	—
Repayments on senior term loan	—	(270.0)
Redemption of APL senior notes	—	(1,168.8)
Costs incurred in connection with financing arrangements	(44.3)	(37.1)
Proceeds from sale of Partnership common and preferred units	—	295.8

Repurchase of shares and units under compensation plans	(0.4)	(4.2)
Contributions from noncontrolling interests	19.1	5.9
Distributions to noncontrolling interests	(6.3)	(5.6)
Payments of distribution equivalent rights	(0.3)	—
Proceeds from issuance of common stock	181.2	336.6
Proceeds from issuance of preferred stock and warrants	994.1	—
Distributions to Partnership unitholders	(144.7)	(221.3)
Dividends to common and preferred shareholders	(201.4)	(78.9)
Net cash provided by (used in) financing activities	(121.6)	1,552.3
Net change in cash and cash equivalents	30.7	24.7
Cash and cash equivalents, beginning of period	140.2	81.0
Cash and cash equivalents, end of period	$ 170.9	$ 105.7

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

Note 1 — Organization and Operations

Our Organization

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

Our Operations

The company is engaged in the business of:

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

Areas of gathering and processing operations include the Permian Basin in West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico. The company’s logistics and marketing assets are predominately located in Mont Belvieu and Galena Park, TX, Lake Charles, LA, and Tacoma, WA. See Note 20 – Segment Information for certain financial information for our business segments.

Note 2 — Basis of Presentation

We have prepared these unaudited consolidated financial statements in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. While we derived the year-end balance sheet data from audited financial statements, this interim report does not include all disclosures required by GAAP for annual periods. These unaudited consolidated financial statements and other information included in this Quarterly Report should be read in conjunction with our consolidated financial statements and notes thereto included in our Annual Report and our Current Report on Form 8-K filed with the SEC on May 23, 2016.

The unaudited consolidated financial statements for the three and six months ended June 30, 2016 and 2015 include all adjustments that we believe are necessary for a fair statement of the results for interim periods. All significant intercompany balances and transactions have been eliminated in consolidation. Certain amounts in prior periods may have been reclassified to conform to the current year presentation.

Our financial results for the three and six months ended June 30, 2016 are not necessarily indicative of the results that may be expected for the full year.

One of our indirect subsidiaries is the sole general partner of Targa Resources Partners LP (“the Partnership” or “TRP”). Prior to February 17, 2016, 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 Incentive Distribution Rights (“IDRs”);

- 16,309,594 common units representing limited partner interests in the Partnership ("common units"), representing an 8.8% limited partnership interest; and
- a Special GP Interest representing retained tax benefits related to the contribution to the Partnership from us of the APL general partner interest acquired in the ATLS merger (as defined in Note 4 – Business Acquisitions).

On February 17, 2016, we completed the transactions contemplated by the Agreement and Plan of Merger (the "TRC/TRP Merger Agreement"), dated November 2, 2015, by and among us, the general partner of TRP, TRC and Spartan Merger Sub LLC, a subsidiary of us ("Merger Sub") and we acquired indirectly all of the outstanding TRP common units that we and our subsidiaries did not already own. Upon the terms and conditions set forth in the TRC/TRP Merger Agreement, Merger Sub merged with and into TRP (the "TRC/TRP Merger"), with TRP continuing as the surviving entity and as a subsidiary of TRC.

At the effective time of the TRC/TRP Merger, each outstanding TRP common unit not owned by us or our subsidiaries was converted into the right to receive 0.62 shares of our common stock. We issued 104,525,775 shares of our common stock to third-party unitholders of the common units of the Partnership in exchange for all of the 168,590,009 outstanding common units of the Partnership that we previously did not own. No fractional shares were issued in the TRC/TRP Merger, and TRP common unitholders instead received cash in lieu of fractional shares. There were no changes to our other interests in the Partnership.

TRP's 5,000,000 9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") remain outstanding after the TRC/TRP Merger. The Preferred Units are listed on the NYSE under "NGLS PRA" and are publicly traded.

As we continue to control the Partnership, the change in our ownership interest as a result of the TRC/TRP Merger is accounted for as an equity transaction, which is reflected in our Consolidated Balance Sheet as a reduction of noncontrolling interests and a corresponding increase in common stock and additional paid in capital. The TRC/TRP Merger is a taxable exchange resulting in a book/tax difference in the basis of the underlying assets acquired (our investment in TRP). A deferred tax liability of approximately $950 million has been recorded, computed as $9.0 billion book basis in excess of $6.5 billion tax basis at our statutory tax rate of 37.11%.

The equity interests in TRP (which are consolidated in our financial statements) that were owned by the public prior to February 17, 2016 are reflected within "Noncontrolling interests" in our Consolidated Balance Sheets for periods prior to the merger date. The earnings recorded by TRP that were attributed to its common units held by the public prior to February 17, 2016 are reflected within "Net income attributable to noncontrolling interests" in our Consolidated Statements of Operations for periods prior to the merger date.

Revisions of Previously Reported Activity in our Consolidated Statements of Comprehensive Income (Loss)

During the first quarter of 2016 we concluded that activity related to our commodity hedge contracts was not reported properly in our Consolidated Statements of Comprehensive Income (Loss) during 2015. The errors resulted in misstatements of the statement caption "Change in fair value" and equal offsetting misstatements of the caption "Settlements reclassified to revenues." Related income tax effects were also misstated.

We concluded that these misstatements were not material to any of the periods affected, as reported "Total Other Comprehensive Income" is unchanged. However, we have revised previous Consolidated Statements of Comprehensive Income (Loss) reported during 2015 to properly reflect changes in fair value and settlements reclassified to revenues. There is no impact on previously reported net income, total comprehensive income, cash flows, financial position or other profitability measures.

The following table displays the impact of these revisions to activity reported in our Consolidated Statements of Comprehensive Income (Loss) during 2015:

	Three Months Ended June 30, 2015						Six Months Ended June 30, 2015					
	As Reported			As Corrected			As Reported			As Corrected		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
Targa Resources Corp.												
Commodity hedging contracts:												
Change in fair value	$ (1.1)	$ 0.4	$ (0.7)	$ (0.5)	$ 0.2	$ (0.3)	$ 0.6	$ (0.2)	$ 0.4	$ 2.0	$ (0.6)	$ 1.4
Settlements reclassified to revenues	(1.8)	0.7	(1.1)	(2.4)	0.9	(1.5)	(2.7)	1.0	(1.7)	(4.1)	1.4	(2.7)
Other comprehensive income (loss) attributable to Targa Resources Corp.	(2.9)	1.1	(1.8)	(2.9)	1.1	(1.8)	(2.1)	0.8	(1.3)	(2.1)	0.8	(1.3)
Noncontrolling interests												
Commodity hedging contracts:												
Change in fair value	(7.6)	-	(7.6)	(3.1)	-	(3.1)	15.9	-	15.9	25.0	-	25.0
Settlements reclassified to revenues	(14.5)	-	(14.5)	(19.0)	-	(19.0)	(21.7)	-	(21.7)	(30.8)	-	(30.8)
Other comprehensive income (loss) attributable to noncontrolling interests	(22.1)	-	(22.1)	(22.1)	-	(22.1)	(5.8)	-	(5.8)	(5.8)	-	(5.8)

Total Commodity hedging contracts:												
Change in fair value	(8.7)	0.4	(8.3)	(3.6)	0.2	(3.4)	16.5	(0.2)	16.3	27.0	(0.6)	26.4
Settlements reclassified to revenues	(16.3)	0.7	(15.6)	(21.4)	0.9	(20.5)	(24.4)	1.0	(23.4)	(34.9)	1.4	(33.5)
Other comprehensive income (loss)	$ (25.0)	$ 1.1	$ (23.9)	$ (25.0)	$ 1.1	$ (23.9)	$ (7.9)	$ 0.8	$ (7.1)	$ (7.9)	$ 0.8	$ (7.1)

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	Three Months Ended September 30, 2015						Nine Months Ended September 30, 2015					
	As Reported			As Corrected			As Reported			As Corrected		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
Targa Resources Corp. Commodity hedging contracts:												
Change in fair value	$ 4.6	$ (1.7)	$ 2.9	$ 5.5	$ (2.0)	$ 3.5	$ 5.2	$ (2.0)	$ 3.2	$ 7.5	$ (2.9)	$ 4.6
Settlements reclassified to revenues	(1.8)	0.7	(1.1)	(2.7)	1.0	(1.7)	(4.5)	1.7	(2.8)	(6.8)	2.6	(4.2)
Other comprehensive income (loss) attributable to Targa Resources Corp.	2.8	(1.0)	1.8	2.8	(1.0)	1.8	0.7	(0.3)	0.4	0.7	(0.3)	0.4
Noncontrolling interests												
Commodity hedging contracts:												
Change in fair value	38.3	-	38.3	45.2	-	45.2	54.2	-	54.2	70.1	-	70.1
Settlements reclassified to revenues	(14.9)	-	(14.9)	(21.8)	-	(21.8)	(36.6)	-	(36.6)	(52.5)	-	(52.5)
Other comprehensive income (loss) attributable to noncontrolling interests	23.4	-	23.4	23.4	-	23.4	17.6	-	17.6	17.6	-	17.6
Total												
Commodity hedging												

contracts:												
Change in fair value	42.9	(1.7)	41.2	50.7	(2.0)	48.7	59.4	(2.0)	57.4	77.6	(2.9)	74.7
Settlements reclassified to revenues	(16.7)	0.7	(16.0)	(24.5)	1.0	(23.5)	(41.1)	1.7	(39.4)	(59.3)	2.6	(56.7)
Other comprehensive income (loss)	$ 26.2	$ (1.0)	$ 25.2	$ 26.2	$ (1.0)	$ 25.2	$ 18.3	$ (0.3)	$ 18.0	$ 18.3	$ (0.3)	$ 18.0

	Year Ended December 31, 2015					
	As Reported			As Corrected		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$ 7.4	$ (2.8)	$ 4.6	$ 11.0	$ (4.2)	$ 6.8
Settlements reclassified to revenues	(5.9)	2.2	(3.7)	(9.5)	3.6	(5.9)
Other comprehensive income (loss) attributable to Targa Resources Corp.	1.5	(0.6)	0.9	1.5	(0.6)	0.9
Noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	73.8	-	73.8	101.7	-	101.7
Settlements reclassified to revenues	(48.9)	-	(48.9)	(76.8)	-	(76.8)
Other comprehensive income (loss) attributable to noncontrolling interests	24.9	-	24.9	24.9	-	24.9
Total						
Commodity hedging contracts:						
Change in fair value	81.2	(2.8)	78.4	112.7	(4.2)	108.5
Settlements reclassified to revenues	(54.8)	2.2	(52.6)	(86.3)	3.6	(82.7)
Other comprehensive income (loss)	$ 26.4	$ (0.6)	$ 25.8	$ 26.4	$ (0.6)	$ 25.8

Note 3 — Significant Accounting Policies

Accounting Policy Updates

The accounting policies that we follow are set forth in Note 3 – Significant Accounting Policies of the Notes to Consolidated Financial Statements in our Annual Report and our Current Report on Form 8-K filed with the SEC on May 23, 2016. There were no significant updates or revisions to our policies during the six months ended June 30, 2016, except as noted below.

Recent Accounting Pronouncements

Revenue from Contracts with Customers

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

With the issuance in August 2015 of ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, the revenue recognition standard is effective for the annual period beginning after December 15, 2017, and for annual and interim periods thereafter. Earlier adoption is permitted for annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. We must retroactively apply the new revenue recognition standard to transactions in all prior periods presented, but will have a choice between either (1) restating each prior period presented or (2) presenting a cumulative effect adjustment in the period the amendment is adopted.

In March 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations. The amendments in this update improve the operability and understandability of the implementation guidance on principal versus agent considerations, including clarifying that an entity should determine whether it is a principal or an agent for each specified good or service promised to a customer. These amendments are effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2017, with early adoption permitted.

In April 2016, the FASB issued ASU 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing. These amendments clarify the guidance on identification of performance obligations and licensing. The amendments include that entities do not have to decide if goods and services are performance obligations if they are considered immaterial in the context of a contract. Entities are also permitted to account for the shipping and handling that takes place after the customer has gained control of the goods as actions to fulfill the contract rather than separate services. In order to identify a performance obligation in a customer contract, an entity has to determine whether the goods or services are distinct, and ASU No. 2016-10 clarifies how the determination can be made.

In May 2016, the FASB issued ASU 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients. These amendments address certain implementation issues related to assessing collectability, presentation of sales taxes, noncash consideration, and completed contracts and contract modifications at transition, and also provide additional practical expedients.

We expect to adopt these updates in their entirety on January 1, 2018, and are continuing to evaluate the impact on our revenue recognition practices.

Consolidation

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. The amendments are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. The amendments are effective for us in 2016 with no impact on our consolidated financial statements or results of operations.

Presentation of Debt Issuance Costs

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The amendments in this update require that debt issuance costs related to a recognized debt liability (other than line-of-credit or other revolving credit facilities) be presented in the Consolidated Balance Sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This update dealt solely with financial statement display matters; recognition and measurement of debt issuance costs were unaffected. We adopted the amendments on January 1, 2016 and have reclassified unamortized debt issuance costs of $42.7 million on our Consolidated Balance Sheet as of December 31, 2015 from Other long-term assets to Long-term debt to conform to current year presentation. Our Consolidated Balance Sheet as of June 30, 2016 has $35.2 million in unamortized debt issuance costs classified in Long-term debt.

Leases

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We expect to adopt the amendments in the first quarter of 2019 and are currently evaluating the impacts of the amendments to our financial statements and accounting practices for leases.

Share-Based Compensation

In March 2016, the FASB issued ASU 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The amendments in this update provide, among other things, that (1) all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit in the income statement with the tax effects of exercised or vested awards treated as discrete items in the reporting period in which they occur and recognition of excess tax benefits regardless of whether the benefit reduces taxes payable in the current period; (2) excess tax benefits should be classified along with other income tax cash flows as an operating activity; (3) an entity can make an entity-wide accounting policy election to either estimate the number of awards that are expected to vest or account for forfeitures when they occur; (4) the threshold to qualify for equity classification permits withholding up to the maximum statutory tax rates in the applicable jurisdictions; and (5) cash paid by an employer when directly withholding shares for tax-withholding purposes should be classified as a financing activity on the statement of cash flows.

We adopted the applicable amendments in the second quarter of 2016 and have applied the guidance as of January 1, 2016. Amendments related to the timing of when excess tax benefits and deficiencies are recognized, minimum statutory withholding requirements, and forfeitures have been applied using a modified retrospective transition method but resulted in no cumulative effect adjustment to equity. The amendment related to the presentation of employee taxes paid on the statement of cash flows when an employer withholds shares to meet the minimum statutory withholding requirement had no impact as we previously classified these payments as a financing activity and continue to do so. The amendment requiring recognition of excess tax benefits and tax deficiencies in the income statement has been applied prospectively. We have elected to apply the amendment related to the presentation of excess tax benefits and deficiencies on the statement of cash flows on a prospective basis and prior periods have not been adjusted. We recognized $2.4 million of excess tax deficiencies in income tax expense for the six months ended

June 30, 2016, which includes $0.5 million attributable to the three months ended March 31, 2016. Our diluted earnings per share calculation has been adjusted for the three and six months ended June 30, 2016, to exclude windfall tax benefits in assumed proceeds under the treasury stock method. In addition, we have elected to account for forfeitures as they occur.

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued ASU 2016-13, Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. These amendments change the measurement of credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The amendments in this update affect investments in loans, investments in debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. The amendments replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. We expect to adopt this guidance on January 1, 2019, and are continuing to evaluate the impact on our measurement of credit losses.

Note 4 – Business Acquisitions

2015 Acquisition

Atlas Mergers

On February 27, 2015, Targa completed the transactions contemplated by the Agreement and Plan of Merger, dated as of October 13, 2014 (the “ATLS Merger Agreement”), by and among (i) Targa, Targa GP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of Targa (“GP Merger Sub”), Atlas Energy L.P., a Delaware limited partnership (“ATLS”) and Atlas Energy GP, LLC, a Delaware limited liability company and the general partner of ATLS (“ATLS GP”), and (ii) Targa and the Partnership completed the transactions contemplated by the Agreement and Plan of Merger (the “APL Merger Agreement” and, together with the ATLS Merger Agreement, the “Atlas Merger Agreements”) by and among Targa, the Partnership, the Partnership’s general partner, Trident MLP Merger Sub LLC, a Delaware limited liability company and a wholly owned subsidiary of the Partnership (“MLP Merger Sub”), ATLS, Atlas Pipeline Partners L.P., a Delaware limited partnership (“APL”) and Atlas Pipeline Partners GP, LLC, a Delaware limited liability company and the general partner of APL (“APL GP”). Pursuant to the terms and conditions set forth in the ATLS Merger Agreement, GP Merger Sub merged (the “ATLS merger”) with and into ATLS, with ATLS continuing as the surviving entity and as a subsidiary of Targa. Pursuant to the terms and conditions set forth in the APL Merger Agreement, MLP Merger Sub merged (the “APL merger” and, together with the ATLS merger, the “Atlas mergers”) with and into APL, with APL continuing as the surviving entity and as a subsidiary of the Partnership. While the Atlas mergers were two separate legal transactions, for GAAP reporting purposes, they are viewed as a single integrated transaction.

In connection with the Atlas mergers, APL changed its name to “Targa Pipeline Partners LP,” which we refer to as TPL, and ATLS changed its name to “Targa Energy LP.”

In addition, prior to the completion of the Atlas mergers, ATLS, pursuant to a separation and distribution agreement entered into by and among ATLS, ATLS GP and Atlas Energy Group, LLC, a Delaware limited liability company (“AEG”), on February 27, 2015, (i) transferred its assets and liabilities other than those related to its “Atlas Pipeline Partners” segment, to AEG and (ii) effected a pro rata distribution to the ATLS unitholders of AEG common units representing a 100% interest in AEG (collectively, the “Spin-Off” and, together with the Atlas mergers, the “Atlas Transactions”).

On February 27, 2015, the Partnership’s partnership agreement (the “Partnership Agreement’) was amended to provide for the issuance of a special general partner interest in the Partnership (the “Special GP Interest”) representing the contribution to the Partnership of the APL GP interest acquired in the ATLS merger totaling $1.6 billion, which is reflected within Additional paid-in capital on the Consolidated Balance Sheets. The Special GP Interest is not entitled to current distributions or allocations of net income or loss, and has no voting rights or other rights except for the limited right to receive deductions attributable to the contribution of APL GP and the right to distributions in liquidation.

The Partnership acquired all of the outstanding units of APL for a total purchase price of approximately $5.3 billion (including $1.8 billion of acquired debt and all other assumed liabilities). Of the $1.8 billion of debt acquired and other liabilities assumed, approximately $1.2 billion of the acquired debt was tendered and settled upon the closing of the Atlas mergers via the Partnership’s January 2015 cash tender offers. These tender offers were in connection with, and conditioned upon, the consummation of the merger with APL. The merger with APL, however, was not conditioned on the consummation of the tender offers. On that same date, we acquired ATLS for a total purchase price of approximately $1.6 billion (including all assumed liabilities).

Pursuant to the APL Merger Agreement, Targa agreed to cause the general partner of the Partnership to amend the Partnership's Partnership Agreement, which we refer to as the "IDR Giveback Amendment", in order to reduce aggregate distributions to us, as the holder of the Partnership's IDRs, by (a) $9,375,000 per quarter during the first four quarters following the APL merger, (b) $6,250,000 per quarter for the next four quarters, (c) $2,500,000 per quarter for the next four quarters and (d) $1,250,000 per quarter for the next four quarters, with the amount of such reductions to be distributed pro rata to the holders of the Partnership's outstanding common units.

TPL is a provider of natural gas gathering, processing and treating services primarily in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States and in the Eagle Ford Shale play in south Texas. The Atlas mergers added TPL's Woodford/SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing operations. In total, TPL added 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The operating results of TPL are reported in our Gathering and Processing segment.

The APL merger was a unit-for-unit transaction with an exchange ratio of 0.5846 of the Partnership's common units (the "APL Unit Consideration") and $1.26 in cash for each APL common unit (the "APL Cash Consideration" and, with the APL Unit Consideration, the "APL Merger Consideration"), a $128.0 million total cash payment, of which $0.6 million was expensed at the acquisition date as the cash payment representing accelerated vesting of a portion of retained employees' APL phantom awards. The Partnership issued

58,614,157 of its common units and awarded 629,231 replacement phantom unit awards with a combined value of approximately $2.6 billion as consideration for the APL merger (based on the $43.82 closing market price of a common unit on the NYSE on February 27, 2015). The cash component of the APL merger also included $701.4 million for the mandatory repayment and extinguishment at closing of the APL Senior Secured Revolving Credit Facility that was to mature in May 2017 (the “APL Revolver”), $28.8 million of payments related to change of control and $6.4 million of cash paid in lieu of unit issuances in connection with settlement of APL equity awards for AEG employees. In March 2015, we contributed $52.4 million to the Partnership to maintain our 2% general partner interest.

In addition, pursuant to the APL Merger Agreement, APL exercised its right under the certificate of designations of the APL 8.25% Class E cumulative redeemable perpetual preferred units (“Class E Preferred Units”) to redeem the APL Class E Preferred Units immediately prior to the effective time of the APL merger.

The ATLS merger was a stock-for-unit transaction with an exchange ratio of 0.1809 of Targa common stock, par value $0.001 per share (the “ATLS Stock Consideration”), and $9.12 in cash for each ATLS common unit (the ATLS Cash Consideration” and, with the ATLS Stock Consideration, the “ATLS Merger Consideration”), (a $514.7 million total cash payment). We issued 10,126,532 of our common shares and awarded 81,740 replacement restricted stock units with a combined value of approximately $1.0 billion for the ATLS merger (based on the $99.58 closing market price of a TRC common share on the NYSE on February 27, 2015). The cash component of the ATLS merger also included approximately $149.2 million of payments related to change of control and cash settlements of equity awards, $88.0 million for repayment of a portion of ATLS outstanding indebtedness and $11.0 million for reimbursement of certain transaction expenses. Approximately $4.5 million of the one-time cash payments and cash settlements of equity awards, which represent accelerated vesting of a portion of retained employees’ ATLS phantom units, were expensed at the acquisition date.

ATLS owned, directly and indirectly, 5,754,253 APL common units immediately prior to closing. Our acquisition of ATLS resulted in us acquiring these common units (converted to 3,363,935 Partnership common units) valued at approximately $147.4 million (based on the $43.82 closing market price of a Partnership common unit on the NYSE on February 27, 2015) and the right to receive the units’ one-time cash payment of approximately $7.3 million, which reduced the consolidated purchase price by approximately $154.7 million.

All outstanding ATLS equity awards, whether vested or unvested, were adjusted in connection with the Spin-Off on the terms and conditions set forth in an Employee Matters Agreement entered into by ATLS, ATLS GP and AEG on February 27, 2015. Following the Spin-Off-related adjustment and at the effective time of the ATLS merger, each outstanding ATLS option and ATLS phantom unit award, whether vested or unvested, held by a person who became an employee of AEG became fully vested (to the extent not vested) and was cancelled and converted into the right to receive the ATLS Merger Consideration in respect of each ATLS common unit underlying the ATLS option or phantom unit award (in the case of options, net of the applicable exercise price). Each outstanding vested ATLS option held by an employee of APL who became an employee of the Company in connection with the Atlas Transactions (a “Midstream Employee”) was cancelled and converted into the right to receive the ATLS Merger Consideration in respect of each ATLS common unit underlying the vested ATLS option, net of the applicable exercise price. Each outstanding unvested ATLS option and each outstanding ATLS phantom unit award held by a Midstream Employee was cancelled and converted into the right to receive (1) the ATLS Cash Consideration in respect of each ATLS common unit underlying such ATLS option or phantom unit award and (2) a TRC restricted stock unit award with respect to a number of shares of TRC Common Stock equal to the product of the ATLS Stock Consideration multiplied by the number of ATLS common units underlying such ATLS option or phantom unit award (in the case of options, net of the applicable exercise price).

In connection with the APL merger, each outstanding APL phantom unit award held by an employee of AEG became fully vested and was cancelled and converted into the right to receive the APL Merger Consideration in respect of each APL common unit underlying the APL phantom unit award. Each outstanding APL phantom unit award held by a Midstream Employee was cancelled and converted into the right to receive (1) the APL Cash Consideration in respect of each APL common unit underlying such APL phantom unit award and (2) a Partnership phantom unit award with respect to a number of the Partnership's common units equal to the product of the APL Unit Consideration multiplied by the number of APL common units underlying such APL phantom unit award.

The acquired business contributed revenues of $616.8 million and net income of $17.8 million to the Company for the period from February 27, 2015 to June 30, 2015, and is reported in our Gathering and Processing segment. As of June 30, 2015, we had incurred $26.8 million of acquisition-related costs. These expenses are included in other expense in our Consolidated Statements of Operations for the six months ended June 30, 2015. As of June 30, 2016, cumulative acquisition-related costs totaled $27.3 million.

Pro Forma Impact of Atlas Mergers on Consolidated Statement of Operations

The following summarized unaudited pro forma Consolidated Statement of Operations information for the six months ended June 30, 2015 assumes that the Partnership's acquisition of APL and our acquisition of ATLS had occurred as of January 1, 2014. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed these acquisitions as of January 1, 2014, or that the results that will be attained in the future. Amounts presented below are in millions.

	June 30, 2015 Pro Forma
Revenues	$3,667.8
Net income	42.4

The pro forma consolidated results of operations amounts have been calculated after applying our accounting policies, and making adjustments to:

- Reflect the change in amortization expense resulting from the difference between the historical balances of APL's intangible assets, net, and the fair value of intangible assets acquired.
- Reflect the change in depreciation expense resulting from the difference between the historical balances of APL's property, plant and equipment, net, and the fair value of property, plant and equipment acquired.
- Reflect the change in interest expense resulting from our financing activities directly related to the Atlas mergers as compared with APL's historical interest expense.
- Reflect the changes in stock-based compensation expense related to the fair value of the unvested portion of replacement Partnership Long Term Incentive Plan ("LTIP") awards which were issued in connection with the acquisition to APL phantom unitholders who continue to provide service as Targa employees following the completion of the APL merger.
- Remove the results of operations attributable to the February 2015 transfer to Atlas Resource Partners, L.P. of 100% of APL's interest in gas gathering assets located in the Appalachian Basin of Tennessee.
- Exclude $26.8 million of acquisition-related costs incurred as of June 30, 2015 from pro forma net income for the six months ended June 30, 2015.
- Reflect the change in APL's revenues and product purchases to report plant sales of Y-grade at contractual net values to conform to our accounting policy.

The following table summarizes the consideration transferred to acquire ATLS and APL:

Fair Value of Consideration Transferred:	
Cash paid, net of cash acquired (1):	
TRC	$745.7
TRP	828.7
Common shares of TRC	1,008.5
Replacement restricted stock units awarded (2)	5.2
Common units of TRP	2,421.1
Replacement phantom units awarded (2)	15.0
Total	$5,024.2

(1) Net of cash acquired of $40.8 million.

(2) The fair value of consideration transferred in the form of replacement restricted stock unit awards and replacement phantom unit awards represent the allocation of the fair value of the awards to the pre-combination service period. The fair value of the awards associated with the post-combination service period will be recognized over the remaining service period of the award.

Our final fair value determination related to the Atlas mergers was as follows.

	February 27,
Fair value determination:	2015
Trade and other current receivables, net	$ 181.1
Other current assets	24.4
Assets from risk management activities	102.1
Property, plant and equipment	4,616.9
Investments in unconsolidated affiliates	214.5
Intangible assets	1,354.9
Other long-term assets	5.5
Current liabilities	(259.3)
Long-term debt	(1,573.3)
Deferred income tax liabilities, net	(13.6)
Other long-term liabilities	(119.1)
Total identifiable net assets	4,534.1
Noncontrolling interest in subsidiaries	(216.9)
Goodwill	707.0
Total fair value of consideration transferred	$ 5,024.2

During the three months ended June 30, 2015, we recorded measurement-period adjustments to our acquisition date fair values due to the refinement of our valuation models, assumptions and inputs. As a result, the Consolidated Statement of Operations for the three months ended March 31, 2015 was retrospectively adjusted for the impact of measurement-period adjustments to property, plant and equipment, intangible assets, and investments in unconsolidated affiliates. These adjustments resulted in a decrease in depreciation and amortization expense of $1.0 million, and an increase in equity earnings of $0.3 million from the amounts previously reported in our Form 10-Q for the quarter ended March 31, 2015.

We adopted the amendments to ASU-2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments on September 30, 2015. As a result, during the six months ended December 31, 2015, we recorded additional quarterly measurement-period adjustments to our acquisition date fair values due to the refinement of our valuation models, assumptions and inputs, as well as adjustments to previously reported preliminary fair values as a result of our review procedures over the development and application of inputs, assumptions and calculations used in cash-flow based fair value measurements associated with business combinations not operating as designed. We recognized these quarterly adjustments in the third and fourth quarters of 2015, with the effect on the Consolidated Statements of Operations resulting from the change to the provisional amounts calculated as if the acquisition had been completed at February 27, 2015.

The valuation of the acquired assets and liabilities was prepared using fair value methods and assumptions including projections of future production volumes and cash flows, benchmark analysis of comparable public companies, expectations regarding customer contracts and relationships, and other management estimates. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 16 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

The excess of the purchase price over the fair value of net assets acquired was approximately $707.0 million, which was recorded as goodwill. The determination of goodwill is attributable to the workforce of the acquired business and the expected synergies. The goodwill is amortizable for tax purposes.

The fair value of assets acquired included trade receivables of $178.1 million. The gross amount due under contracts was $178.1 million, all of which was expected to be collectible. The fair value of assets acquired included other receivables of $3.0 million reported in current receivables and $4.5 million reported in other long-term assets related to a contractual settlement with a counterparty.

Mandatorily Redeemable Preferred Interests

Other long-term liabilities acquired included $109.3 million related to mandatorily redeemable preferred interests held by our partner in two joint ventures (see Note 10 – Other Long-Term Liabilities).

Contingent Consideration

A liability arising from the contingent consideration for APL's previous acquisition of a gas gathering system and related assets has been recognized at fair value. APL agreed to pay up to an additional $6.0 million if certain volumes are achieved on the acquired gathering system within a specified time period. The fair value of the remaining contingent payment is recorded within other long term liabilities on our Consolidated Balance Sheets. The range of the undiscounted amount that we could pay related to the remaining contingent payment is between $0.0 and $6.0 million. We finalized our acquisition analysis and modeling of this contingent liability during the three months ended June 30, 2015, which resulted in an acquisition date fair value of $4.2 million. Subsequent changes in the fair value of this liability are included in earnings.

Replacement Restricted Stock Units ("RSUs")

In connection with the ATLS merger, we awarded RSUs in accordance with and as required by the Atlas Merger Agreements to those APL employees who became Targa employees after the acquisition. The vesting dates and terms remained unchanged from the existing ATLS awards, and will vest over the remaining terms of the awards, which are either 25% per year over the original four year term or 25% after the third year of the original term and 75% after the fourth year of the original term.

Each RSU will entitle the grantee to one common share on the vesting date and is an equity-settled award. The RSUs include dividend equivalents. When we declare and pay cash dividends, the holders of RSUs will be entitled within 60 days to receive cash payment of dividend equivalents in an amount equal to the cash dividends the holders would have received if they were the holders of record on the record date of the number of our common shares related to the RSUs.

The fair value of the RSUs was based on the closing price of our common shares at the close of trading on February 27, 2015. The fair value was allocated between the pre-acquisition and post-acquisition periods to determine the amount to be treated as purchase consideration and future compensation expense, respectively. Compensation cost will be recognized in general and administrative expense over the remaining service period of each award.

Replacement Phantom Units

In connection with the APL merger, the Partnership awarded replacement phantom units in accordance with and as required by the Atlas Merger Agreements to those APL employees who became Targa employees after the acquisition. The vesting dates and terms remained unchanged from the existing APL awards, and will vest over the remaining terms of the awards, which are either 25% per year over the original four year term or 33% per year over the original three year term.

Each replacement phantom unit will entitle the grantee to common stock on the vesting date and is an equity-settled award. The replacement phantom units include distribution equivalent rights ("DERs"). When the Partnership declares and pays cash distributions, the holders of replacement phantom units will be entitled within 60 days to receive cash payment of DERs in an amount equal to the cash distributions the holders would have received if they were the holders of record on the record date of the number of the Partnership's common units related to the replacement phantom units.

The fair value of the replacement phantom units was based on the closing price of the Partnership's units at the close of trading on February 27, 2015. The fair value was allocated between the pre-acquisition and post-acquisition periods to determine the amount to be treated as purchase consideration and compensation expense, respectively. Compensation cost will be recognized in general and administrative expense over the remaining service period of each award.

Goodwill

We recognized goodwill at a fair value of approximately $707.0 million associated with the Atlas mergers as of the acquisition date on February 27, 2015. Goodwill has been attributed to the WestTX, SouthTX and SouthOK reporting units in our Gathering and Processing segment. As a result, any level of decrease in the forecasted cash flows from the date of acquisition would likely result in the fair value of the reporting unit to fall below the carrying value of the reporting unit, and could result in an impairment of that reporting unit’s goodwill.

As described in Note 3 – Significant Accounting Policies, we evaluate goodwill for impairment at least annually on November 30, or more frequently if we believe necessary based on events or changes in circumstances. As of December 31, 2015, we had not completed our November 30, 2015 impairment assessment. Based on the results of that preliminary evaluation, we recorded a provisional goodwill impairment of $290.0 million during the fourth quarter of 2015. The provisional goodwill impairment reduced the carrying value of goodwill to $417.0 million on our Consolidated Balance Sheets as of December 31, 2015.

During the first quarter of 2016, we finalized our evaluation of goodwill for impairment and recorded additional impairment expense of $24.0 million in our Consolidated Statement of Operations and reduced the carrying value of goodwill to $393.0 million on our Consolidated Balance Sheets. The impairment of goodwill is primarily due to the effects of lower commodity prices, and a higher cost of capital for companies in our industry compared to conditions in February 2015 when we acquired Atlas. Our evaluation as of November 30, 2015 utilized the income approach (a discounted cash flow analysis ("DCF")) to estimate the fair values of our reporting units. The future cash flows for our reporting units are based on our estimates, at that time, of future revenues, income from operations and other factors, such as working capital and capital expenditures. We take into account current and expected industry and market conditions, commodity pricing and volumetric forecasts in the basins in which the reporting units operate. The discount rates used in our DCF analysis are based on a weighted average cost of capital determined from relevant market comparisons.

Changes in the gross amounts of our goodwill and impairment loss are as follows:

	WestTX	SouthTX	SouthOK	Total
Beginning of period January 1, 2015	$ —	$ —	$ —	$ —
Acquisition February 27, 2015	364.5	160.3	182.2	707.0
Provisional Impairment	(37.6)	(70.2)	(182.2)	(290.0)
Goodwill December 31, 2015	326.9	90.1	—	417.0
Additional Impairment	(14.4)	(9.6)	—	(24.0)
Goodwill June 30, 2016	$ 312.5	$ 80.5	$ —	$ 393.0

The sustained decrease and uncertain outlook in commodity prices and volumes have adversely impacted our customers and their future capital and operating plans. A continued or prolonged period of lower commodity prices could result in further deterioration of reporting unit fair values and potential further impairment charges related to goodwill and property, plant and equipment. There were no impairment triggers identified or further impairment charges recognized in the second quarter of 2016.

Note 5 — Inventories

	June 30, 2016	December 31, 2015
Commodities	$ 99.1	$ 128.3
Materials and supplies	11.9	12.7
	$ 111.0	$ 141.0

Note 6 — Property, Plant and Equipment and Intangible Assets

	June 30, 2016	December 31, 2015	Estimated Useful Lives (In Years)
Gathering systems	$6,416.5	$6,304.5	5 to 20
Processing and fractionation facilities	3,289.2	2,995.2	5 to 25
Terminaling and storage facilities	1,186.4	1,115.0	5 to 25
Transportation assets	454.7	454.0	10 to 25
Other property, plant and equipment	229.5	221.1	3 to 25
Land	120.6	108.8	—
Construction in progress	532.5	736.5	—
Property, plant and equipment	12,229.4	11,935.1	
Accumulated depreciation	(2,526.9)	(2,232.4)	
Property, plant and equipment, net	$9,702.5	$9,702.7	
Intangible assets	$2,036.6	$2,036.6	20
Accumulated amortization	(310.6)	(226.5)	
Intangible assets, net	$1,726.0	$1,810.1	

Intangible assets consist of customer contracts and customer relationships acquired in the Atlas mergers in 2015 and our Badlands business acquisition in 2012. The fair values of these acquired intangible assets were determined at the date of acquisition based on the present values 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.

The fair values of intangible assets acquired in the Atlas mergers have been recorded at a fair value of $1,354.9 million and are being amortized over a 20 year life using the straight-line method. Amortization expense attributable to our intangible assets related to the Badlands acquisition is recorded using a method that closely reflects the cash flow pattern underlying their intangible asset valuation.

	June 30, 2016	December 31, 2015
Beginning of period	$ 1,810.1	$ 591.9
Additions from acquisition	—	1,354.9
Amortization	(84.1)	(136.7)
Intangible assets, net	$ 1,726.0	$ 1,810.1

Note 7 – Investments in Unconsolidated Affiliates

Our unconsolidated investments consist of a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP ("GCF") and three non-operated joint ventures in South Texas acquired in the Atlas mergers in 2015: 75% interest in T2 LaSalle; 50% interest in T2 Eagle Ford; and 50% interest in T2 EF Cogen (together the "T2 Joint Ventures"). The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The terms of these joint venture agreements do not afford us the degree of control required for consolidating them in our consolidated financial statements, but do afford us the significant influence required to employ the equity method of accounting. Our maximum exposure to loss as a result of our involvement with the T2 Joint Ventures includes our equity investment, any additional capital contribution commitments and our share of any operating expenses incurred by the T2 Joint Ventures.

The following table shows the activity related to our investments in unconsolidated affiliates:

	GCF	T2 LaSalle	T2 Eagle Ford	T2 EF Cogen	Total
December 31, 2015	$ 49.5	$ 63.6	$ 123.8	$ 22.0	$ 258.9
Equity earnings (loss)	(0.6)	(2.8)	(4.1)	(1.7)	(9.2)
Cash distributions (1)	(3.5)	—	—	(0.4)	(3.9)
Cash calls for expansion projects	—	—	4.4	—	4.4
June 30, 2016	$ 45.4	$ 60.8	$ 124.1	$ 19.9	$ 250.2

(1) Includes $3.9 million in distributions received from GCF and the T2 Joint Ventures in excess of our share of cumulative earnings for the six months ended June 30, 2016. Such excess distributions are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

The recorded value of the T2 Joint Ventures is based on fair values at the date of acquisition which results in an excess fair value of $39.8 million over the book value of the joint venture capital accounts as of June 30, 2016. This basis difference is attributable to depreciable tangible assets and is being amortized over the estimated useful lives of the underlying assets of 20 years on a straight-line basis and is included as a component of equity earnings. See Note 4 - Business Acquisitions for further information regarding the fair value determinations related to the Atlas mergers.

Note 8 — Accounts Payable and Accrued Liabilities

	June 30, 2016	December 31, 2015
Commodities	$439.5	$ 385.2
Other goods and services	89.3	142.9
Interest	69.7	81.0
Compensation and benefits	24.3	16.0
Income and other taxes	34.8	13.4
Other	40.1	18.6
	$697.7	$ 657.1

Accounts payable and accrued liabilities includes $17.5 million and $34.2 million of liabilities to creditors to whom we have issued checks that remain outstanding as of June 30, 2016 and December 31, 2015.

Note 9 — Debt Obligations

	June 30, 2016	December 31, 2015
Current:		
Obligations of the Partnership		
Accounts receivable securitization facility, due December 2016 (1)	$225.0	$219.3
Long-term:		
TRC obligations:		
TRC Senior secured revolving credit facility, variable rate, due February 2020 (2)	275.0	440.0
TRC Senior secured term loan, variable rate, due February 2022	160.0	160.0
Unamortized discount	(2.4)	(2.5)
Obligations of the Partnership: (1)		
Senior secured revolving credit facility, variable rate, due October 2017 (3)	55.0	280.0
Senior unsecured notes:		
5% fixed rate, due January 2018	733.6	1,100.0
4 % fixed rate, due November 2019	749.4	800.0
6 % fixed rate, due October 2020 (4)	309.9	342.1
Unamortized premium	4.1	5.0
6 % fixed rate, due February 2021	478.6	483.6
Unamortized discount	(20.2)	(22.1)
6 % fixed rate, due August 2022	278.7	300.0
5¼% fixed rate, due May 2023	559.6	583.7
4¼% fixed rate, due November 2023	583.9	623.5
6¾% fixed rate, due March 2024	580.1	600.0
APL notes, 6 % fixed rate, due October 2020 (4) (5)	12.9	12.9
Unamortized premium	0.2	0.2
APL notes, 4¾% fixed rate, due November 2021 (5)	6.5	6.5
APL notes, 5 % fixed rate, due August 2023 (5)	48.1	48.1
Unamortized premium	0.5	0.5
	4,813.5	5,761.5
Debt issuance costs	(35.2)	(42.7)
Total long-term debt	4,778.3	5,718.8
Total debt	$5,003.3	$5,938.1
Irrevocable standby letters of credit:		
Letters of credit outstanding under the TRC Senior secured credit facility (2)	$—	$—
Letters of credit outstanding under the Partnership senior secured revolving credit facility (3)	13.3	12.9
	$13.3	$12.9

(1) 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.
(2) As of June 30, 2016, availability under TRC's $670 million senior secured revolving credit facility ("TRC Revolver") was $395.0 million.
(3) As of June 30, 2016, availability under the Partnership's $1.6 billion senior secured revolving credit facility ("TRP Revolver") was $1,531.7 million.
(4) In May 2015, the Partnership exchanged TRP 6 % Senior Notes with the same economic terms to holders of the 6 % APL Notes that validly tendered such notes for exchange to us.
(5) APL debt is not guaranteed by us or the Partnership.

The following table shows the range of interest rates and weighted average interest rate incurred on variable-rate debt obligations during the six months ended June 30, 2016:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC senior secured revolving credit facility	2.2% - 4.5%	2.4%
TRC senior secured term loan	5.75%	5.75%
Partnership's senior secured revolving credit facility	2.4% - 4.8%	2.6%
Partnership's accounts receivable securitization facility	1.2%	1.2%

Compliance with Debt Covenants

As of June 30, 2016, we were in compliance with the covenants contained in our various debt agreements.

Debt Repurchases

During the six months ended June 30, 2016, the Partnership repurchased on the open market a portion of its outstanding Senior Notes as follows:

Debt Repurchased	Book Value	Payment	Gain/(Loss)	Write-off of Debt Issuance Costs	Net Gain (Loss)
5¼% Senior Notes	24.1	(20.1)	4.0	(0.2)	3.8
4¼% Senior Notes	39.5	(31.8)	7.7	(0.3)	7.4
6 % Senior Notes	4.8	(4.3)	0.5	(0.1)	0.4
6 % Senior Notes	32.6	(29.5)	3.1	-	3.1
6 % Senior Notes	21.3	(18.7)	2.6	(0.2)	2.4
6¾% Senior Notes	19.9	(17.5)	2.4	(0.2)	2.2
5% Senior Notes	366.4	(368.2)	(1.8)	(2.1)	(3.9)
4 % Senior Notes	50.6	(44.2)	6.4	(0.4)	6.0
	$559.2	$(534.3)	$ 24.9	$ (3.5)	$ 21.4

We or TRP may retire or purchase various series of TRP's outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Contractual Obligations

The following table summarizes payment obligations for debt instruments after giving effect to 2016 debt repurchases:

	Payments Due By Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(in millions)				
Partnership Senior Unsecured Debt:					
Debt obligations (1)	$ 4,341.3	$ -	$ 733.6	$ 1,550.8	$ 2,056.9
Interest on debt obligations (2)	1,223.5	239.3	419.2	317.4	247.6
	$ 5,564.8	$ 239.3	$ 1,152.8	$ 1,868.2	$ 2,304.5

(1) Represents scheduled future maturities of consolidated debt obligations for the periods indicated.
(2) Represents interest expense on debt obligations based on both fixed debt interest rates and prevailing June 30, 2016 rates for floating debt.

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Note 10 — Other Long-term Liabilities

Other long-term liabilities are comprised of the following obligations:

	June 30, 2016	December 31, 2015
Asset retirement obligations	$63.6	$ 70.4
Mandatorily redeemable preferred interests	68.3	82.9
Deferred revenue and other	32.6	26.9
Total long-term liabilities	$164.5	$ 180.2

Asset Retirement Obligations

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

December 31, 2015	$70.4
Change in cash flow estimate	(9.1)
Accretion expense	2.3
June 30, 2016	$63.6

Mandatorily Redeemable Preferred Interests

Our consolidated financial statements include our interest in two joint ventures that, separately, own a 100% interest in the WestOK natural gas gathering and processing system and a 72.8% undivided interest in the WestTX natural gas gathering and processing system. Our partner in the joint ventures holds preferred interests in each joint venture that are redeemable: (i) at our or our partner's election, on or after July 27, 2022; and (ii) mandatorily, in July 2037.

For reporting purposes under GAAP, an estimate of our partner's interest in each joint venture is required to be recorded as if the redemption had occurred on the reporting date. Because redemption will not be required at least until 2022, the actual value of our partner's allocable share of each joint venture's assets at the time of redemption may differ from our estimate of redemption value as of June 30, 2016.

The following table shows the changes attributable to mandatorily redeemable preferred interests:

December 31, 2015	$82.9
Change in estimated redemption value	(14.6)

June 30, 2016	$68.3

Note 11 – Preferred Stock

Preferred Stock and Detachable Warrants

In the first quarter of 2016, TRC sold in two tranches to investors in a private placement 965,100 shares of Series A Preferred Stock ("Series A Preferred") with detachable Series A Warrants exercisable into a maximum of 13,550,004 shares of our common stock and Series B Warrants exercisable into a maximum of 6,533,727 shares of our common stock (collectively the "Warrants") for an aggregate purchase price of $994.1 million in cash.

The Series A Preferred have a liquidation value of $1,000 per share and bears a cumulative 9.5% fixed dividend payable quarterly 45 days after the end of each fiscal quarter. The Company may, at the sole election of the Board of Directors, elect to pay dividends for any quarter with a paid-in-kind election ("PIK") through December 31, 2017. Under the PIK election, unpaid dividends would be added to the liquidation preference and a commensurate amount of Series A and Series B Warrants would be issued. The $177.2 million discount on the Series A Preferred created by the relative fair value allocation of proceeds, which is not subject to periodic accretion, would be reported as a deemed dividend in the event a redemption occurs. The Series A Preferred have no mandatory redemption date, but is redeemable at our election in year six for a 10% premium to the liquidation preference and for a 5% premium to the liquidation preference thereafter. If the Series A Preferred is not redeemed by the end of year twelve, the investors have the right to convert the Series A Preferred into TRC common stock at an exercise price of $20.77, which represented a 10% premium over the ten day VWAP (volume weighted average price) prior to the February 18 signing date ($18.88) of the Purchase Agreement underlying the first tranche. If the investors do not elect to convert their Series A Preferred into TRC common stock, Targa has a right after year twelve to force conversion, but only if the VWAP for the ten preceding trading days is greater than 120% of the conversion price. A change of control provision could result in forced redemption, at the option of the investor, if the Series A Preferred could not otherwise remain outstanding or be replaced with a "substantially equivalent security." The change of control premium to the liquidation preference on the redemption is initially 25% in year one, 20% in year two, 15% in year three, 10% in years four through six and 5% thereafter.

The Series A Preferred ranks senior to the common outstanding stock with respect to the payment of dividends and distributions in liquidation. The holders of Series A Preferred generally only have voting rights in certain circumstances, subject to certain exceptions, which include:

- the issuance or the increase by the Company of any specific class or series of stock that is senior to the Series A Preferred,
- the issuance or the increase by any of the Company's consolidated subsidiaries of any specific class or series of securities,
- changes to the Certificates of Incorporation or Designations of the Series A Preferred that would materially and adversely affect the Preferred Stock holder,
- the issuance of stock on parity with the Series A Preferred, subject to certain exceptions, if the Company has exceeded a stipulated fixed charge coverage ratio or an aggregate amount of net proceeds from all future issuances of Parity Stock, or would use the proceeds of such issuance to pay dividends,
- the incurrence of indebtedness, other than indebtedness that complies with a stipulated fixed charge coverage ratio or under the TRC and TRP Credit Agreements (or replacement commercial bank facilities) in an aggregate amount up to $2.75 billion.

In addition, observation right status as a Board Observer was granted to an investor with the right to attend full meetings of the Board of Directors (the "Board") for TRC and to receive materials other members of the Board receive. Only in the event (i) we have not paid distributions with respect to two full quarters (whether or not consecutive) on the Series Preferred or (ii) an event of default occurs with respect only to the financial covenants under the TRC and TRP Credit Agreements, will the investor have the right to turn the Board Observer into a member of the Board to serve until (x) all accrued and unpaid distributions on the Series A Preferred are paid or (y) there is no longer such an event of default, as applicable.

The Series A Preferred is a hybrid security and is viewed as a debt host for the purpose of evaluating embedded derivatives. Bifurcation of the Company's redemption provision is not required because the redemption provision is clearly and closely related to the preferred debt host. Further, both our and the investors' conversion options qualify for a derivatives scope exception under ASC 815 – Derivatives and Hedging ("ASC 815") applicable to embedded features that are indexed to an entity's equity, and that would be classified as equity if freestanding. The Series A Preferred does not qualify as an equity liability instrument under ASC 480 – Distinguishing Liabilities from Equity, because it is not mandatorily redeemable. However, as SEC Regulation S-X, Rule 5-02-27 does not permit a probability assessment for a change of control provision our Series A Preferred must be presented as mezzanine equity between liabilities and shareholders' equity on our Consolidated Balance Sheets because a change of control event, although not considered probable, could force the Company to redeem the Series A Preferred. At each balance sheet date we must re-evaluate whether the Series A Preferred continues to qualify for treatment as an equity instrument. Under the terms of the Registration Rights Agreement covering common stock issuable upon conversion of the Series A Preferred (the "Preferred Registration Rights Agreement"), we will cause a registration statement with respect to the common shares underlying the Series A Preferred to be declared effective within 12 years of the March 16, 2016 issue date (the "Effective Date"), and pay liquidated damages in the event we fail to do so. A maximum of 46,466,057 common shares would be issued upon conversion of the Series A Preferred.

The detachable Warrants have a seven year term and are exercisable beginning on September 16, 2016. They were issued in two series: Series A Warrants exercisable into a maximum number of 13,550,004 shares of our common stock with an exercise price of $18.88 and 6,533,727 Series B Warrants with an exercise price of $25.11. The Warrants may be net settled in cash or shares of common stock at the Company's option. The Warrants qualify as freestanding financial instruments and meet the derivatives accounting scope exception in ASC 815 because they are indexed to our equity and otherwise meet the applicable criteria for equity classification. The portion of proceeds allocated to the Series A and Series B Warrants was recorded as additional paid-in capital. Pursuant to the terms of the Registration Rights Agreement covering the common stock issuable upon exercise of the Warrants (the "Warrants Registration Rights Agreement"), we filed a prospectus supplement on June 30, 2016 (the "Warrants Prospectus Supplement") to our Registration Statement on Form S-3 filed with the SEC on May 23, 2016 (the "May 2016 Shelf" and together with the Warrants Prospectus Supplement, the "Warrants Registration Statement") for the registered resale by the selling stockholders described therein of 20,083,731 common shares, which is the maximum amount that could be issued upon conversion of the Warrants. We have granted certain demand and piggyback registration rights with respect to the holders of the common shares underlying the Warrants pursuant to the Warrants Registration Rights Agreement. Also under the Warrants Registration Rights Agreement, we are required to use commercially reasonable efforts to keep the Warrants Registration Statement to be continuously effective, until the earliest to occur of the following: (a) the date on which all Registrable Securities (as defined under the Warrants Registration Rights Agreement) covered by the Warrants Registration Statement have been distributed, (b) the date on which there are no longer any Registrable Securities outstanding and (c) the later of (1) the fourth anniversary of the date on which all Warrants have been converted into common shares and (2) if and only if any holder of Registrable Securities is an "affiliate" (as such term is defined in Rule 144 promulgated under the Securities Act) of the Company, the earlier of (x) the date on which such holder is no longer an "affiliate" (as such term is defined in Rule 144 promulgated under the Securities Act) of the Company and (y) March 16, 2028.

Under the Preferred Registration Rights Agreement, if the registration statement is not declared effective by the applicable required effective date, each record holder of the securities to be registered would receive liquidated damages. The Liquidated Damages Multiplier ("the multiplier") is calculated as the product of (1) the purchased Series A Preferred Stock price and (ii) the number of registrable securities by the applicable record holder of any registrable securities. The liquidated damages, which would accrue daily, are an amount equal to 0.25% of the multiplier for the first 60 day period following the Effective Date plus an additional 0.25% of the multiplier for each subsequent 60 days (i.e. 0.5% for 61-120 days, 0.75% for 121-180 days, and 1.0% thereafter), up to a maximum amount equal to 1.0% of the multiplier thereafter. There is no limitation for the maximum potential consideration of liquidated damages. Management believes that remittance of any future payments under these provisions is not probable and therefore has not attributed any allocation of offering proceeds to a contingent liability for registration payment arrangements under ASC 825-20 – Financial Instruments-Registration Payment Arrangements ("ASC 825-20").

Net cash proceeds of $970.3 million (which reflects payment of $23.8 million transaction fees), were allocated on a relative fair value basis to the Series A Preferred ($787.9 million), Series A Warrants ($135.8 million) and Series B Warrants ($46.6 million). The $177.2 million discount on the Series A Preferred created by the relative fair value allocation of proceeds, which is not subject to periodic accretion, would be reported as a deemed dividend in the event a redemption occurs. As described below, $614.4 million of the $787.9 million allocated to the Series A Preferred is allocated to additional paid-in capital to give effect to the intrinsic value of a beneficial conversion feature ("BCF").

Beneficial Conversion Feature

ASC 470-20-20 – Debt – Debt with conversion and Other Options ("ASC 470-20") defines a beneficial conversion feature ("BCF") as a nondetachable conversion feature that is in the money at the issuance date. We are required by ASC 470-20 to allocate a portion of the proceeds from the preferred offering equal to the intrinsic value of the BCF to additional paid-in capital. The intrinsic value of the BCF is calculated at the issuance date as the difference between the "accounting conversion price" and the market price of our common shares multiplied by the number of number of shares into which our Series A Preferred is convertible. The accounting conversion price of $17.02 per share is different from the $20.77 per share contractual conversion price. It is derived by dividing the proceeds allocated to the Series A Preferred by the number of common shares into which the Series A preferred shares are convertible. We are recording the accretion of the $614.4 million Series A Preferred discount attributable to the BCF as a deemed dividend using the effective yield method over the twelve year period prior to the effective date of the holders' conversion right.

We have the right to redeem the Series A Preferred beginning after year five. As such, we can effectively mitigate or limit the Series A Preferred Holders' ability to benefit from their conversion right after year twelve by paying either a $96.5 million (10%) redemption premium in year six or a $48.3 million (5%) redemption premium in years seven through twelve. In either case, the redemption premium would be significantly less than the $614.4 million BCF required to be recognized under GAAP.

The following table summarizes the accounting upon issuance of our Series A Preferred:

		Allocation of Proceeds			
			Additional Paid-in Capital		
		Series A Preferred Stock	Series A Warrants	Series B Warrants	Beneficial Conversion Feature (BCF)
Gross proceeds	$994.1				
Transaction fees	(23.8)				
Net Proceeds- Initial Relative Fair Value Allocation	$970.3	$787.9	$135.8	$ 46.6	$ —
Allocation to BCF		(614.4)	—	—	614.4
Per balance sheet upon issuance		$173.5	$135.8	$ 46.6	$ 614.4

Preferred Stock Dividends

As of June 30, 2016, we have accrued preferred dividends of $22.9 million, which will be paid on August 12, 2016. We paid $3.8 million of dividends to preferred shareholders during the six months ended June 30, 2016. During the six months ended June 30, 2016, we recorded deemed dividends of $6.5 million attributable to accretion of the preferred discount resulting from the BCF accounting described above.

Note 12 — Partnership Units and Related Matters

Preferred Units

As of June 30, 2016, the Partnership has 5,000,000 Preferred Units outstanding. The Partnership paid $5.6 million of distributions to preferred unitholders during the six months ended June 30, 2016. The Preferred Units are reported as noncontrolling interests in our financial statements.

Subsequent Event

On July 18, 2016, the board of directors of the general partner of the Partnership declared a monthly cash distribution of $0.1875 per preferred unit for July 2016. This distribution will be paid on August 15, 2016.

Distributions

In accordance with the Partnership Agreement, the Partnership must distribute all of its available cash, as defined in the Partnership Agreement, and as determined by the general partner, to preferred unitholders monthly and to common unitholders of record within 45 days after the end of each quarter. As a result of the TRC/TRP Merger, we are entitled to receive all available Partnership distributions after payment of preferred distributions each quarter. The following details the distributions declared and paid by the Partnership, net of the IDR Giveback, during 2016:

- On February 9, 2016, total distributions of $200.4 million were declared and paid for the three months ended December 31, 2015, of which $61.4 million was paid to us.
- On May 12, 2016, distributions declared for the three months ended March 31, 2016 of $154.8 million were paid to us.
- On July 20, 2016, distributions of $178.9 million were declared for the three months ended June 30, 2016, which will be paid to us on August 11, 2016.

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Note 13 — Common Stock and Related Matters

Public Offerings of Common Stock

In May 2016, we entered into an Equity Distribution Agreement under the May 2016 Shelf (the "May 2016 EDA") with Barclays Capital Inc., Capital One Securities Inc., Citigroup Global Markets Inc., Deutsche Bank Securities Inc., Goldman, Sachs & Co., Jefferies LLC, J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc., and Wells Fargo Securities, LLC, as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $500.0 million of our common stock. The common stock available for sale under the May 2016 EDA were validly registered pursuant to the registration statement on Form S-3 filed on May 23, 2016. During the three months ended June 30, 2016, we issued 5,105,652 shares of common stock under the May 2016 EDA, receiving net proceeds of $215.1 million, of which $36.0 million was received in July 2016.

Subsequent Event

In July 2016, we issued 781,262 shares of common stock for which we received proceeds of $32.7 million, net of commissions and fees, pursuant to the May 2016 EDA.

TRC/TRP Merger

On February 17, 2016, we completed the TRC/TRP Merger (see Note 2 – Basis of Presentation).

Dividends

The following table details the dividends declared and/or paid by us to common shareholders for the six months ended June 30, 2016:

Three Months Ended	Date Paid or To Be Paid	Total Dividends Declared	Amount of Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
(In millions, except per share amounts)					
June 30, 2016	August 15, 2016	$ 153.1	$ 151.6	$ 1.5	$ 0.91000
March 31, 2016	May 16, 2016	147.8	146.1	1.7	0.91000
December 31, 2015	February 9, 2016	51.7	51.0	0.7	0.91000

(1) Represents accrued dividends on restricted stock and restricted stock units that are payable upon vesting. Dividends declared are recorded as a reduction of retained earnings to the extent that retained earnings was available at the close of the prior quarter, with any excess recorded as a reduction of additional paid-in capital.

Note 14 — Earnings per Common Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income	$(14.6)	$23.8	$(15.2)	$59.7
Less: Net income attributable to noncontrolling interests	8.6	8.6	10.7	41.1
Less: Dividends on preferred stock	29.4	—	33.2	—
Net income attributable to common shareholders for basic earnings per share	$(52.6)	$15.2	$(59.1)	$18.6
Weighted average shares outstanding - basic	161.6	55.9	134.1	50.9
Net income available per common share - basic	$(0.33)	$0.27	$(0.44)	$0.37
Weighted average shares outstanding	161.6	55.9	134.1	50.9
Dilutive effect of unvested stock awards	—	0.2	—	0.1

Weighted average shares outstanding - diluted	161.6	56.1	134.1	51.0
Net income available per common share - diluted	$(0.33)	$0.27	$(0.44)	$0.36

The following potential common stock equivalents are excluded from the determination of diluted earnings per share because the inclusion of such shares would have been anti-dilutive (in millions on a weighted-average basis):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Unvested restricted stock awards	0.6	—	0.3	—
Warrants to purchase common stock	9.3	—	5.0	—
Series A preferred stock	46.5	—	27.3	—

Note 15 — Derivative Instruments and Hedging Activities

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

The hedges generally match the NGL product composition and the NGL delivery points of our physical equity volumes. Our natural gas hedges are a mixture of specific gas delivery points and Henry Hub. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition. We believe this approach avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as “proxy” hedges of NGL prices. Our natural gas and NGL hedges are settled using published index prices for delivery at various locations.

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

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to us and included in the acquisition date fair value of assets acquired. Derivative settlements of $67.9 million and $15.1 million related to these novated contracts were received during the year ended December 31, 2015 and the six months ended June 30, 2016. These settlements were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired and had no effect on results of operations.

The "off-market" nature of these acquired derivatives can introduce a degree of ineffectiveness for accounting purposes due to an embedded financing element representing the amount that would be paid or received as of the acquisition date to settle the derivative contract. The resulting ineffectiveness can either potentially disqualify the derivative contract in its entirety for hedge accounting or alternatively affect the amount of unrealized gains or losses on qualifying derivatives that can be deferred from inclusion in periodic net income. Additionally, for the three and six months ended June 30, 2016, we recorded $0.3 million and $0.3 million of ineffectiveness gains related to otherwise qualifying APL derivatives, which are primarily natural gas swaps.

At June 30, 2016, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2016	2017	2018	2019
Natural Gas	Swaps	MMBtu/d	130,587	70,282	47,200	8,083
Natural Gas	Basis Swaps	MMBtu/d	41,005	18,082	-	-
Natural Gas	Options	MMBtu/d	22,900	22,900	9,486	-
NGL	Swaps	Bbl/d	2,899	1,848	978	79
NGL	Futures	Bbl/d	4,750	3,145	-	-
NGL	Options	Bbl/d	920	1,468	1,676	-
Condensate	Swaps	Bbl/d	2,770	1,850	1,350	223
Condensate	Options	Bbl/d	790	790	101	-

We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

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

		Fair Value as of June 30, 2016		Fair Value as of December 31, 2015	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 41.4	$ 14.8	$ 92.1	$ 2.1
	Long-term	13.6	19.7	34.9	2.4
Total derivatives designated as hedging instruments		$ 55.0	$ 34.5	$ 127.0	$ 4.5
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ —	$ 0.1	$ 0.1	$ 3.1
Total derivatives not designated as hedging instruments		$ —	$ 0.1	$ 0.1	$ 3.1
Total current position		$ 41.4	$ 14.9	$ 92.2	$ 5.2
Total long-term position		13.6	19.7	34.9	2.4
Total derivatives		$ 55.0	$ 34.6	$ 127.1	$ 7.6

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

June 30, 2016	Gross Presentation Asset	Gross Presentation Liability	Pro Forma Net Presentation Asset	Pro Forma Net Presentation Liability
Current Position				
Counterparties with offsetting positions	$40.2	$ 14.1	$26.1	$ -
Counterparties without offsetting positions - assets	1.2	-	1.2	-
Counterparties without offsetting positions - liabilities	-	0.8	-	0.8
	41.4	14.9	27.3	0.8
Long Term Position				
Counterparties with offsetting positions	13.6	17.2	-	3.6
Counterparties without offsetting positions - assets	-	-	-	-
Counterparties without offsetting positions - liabilities	-	2.5	-	2.5
	13.6	19.7	-	6.1
Total Derivatives				
Counterparties with offsetting positions	53.8	31.3	26.1	3.6
Counterparties without offsetting positions - assets	1.2	-	1.2	-
Counterparties without offsetting positions - liabilities	-	3.3	-	3.3
	$55.0	$ 34.6	$27.3	$ 6.9

December 31, 2015	Gross Presentation Asset	Gross Presentation Liability	Pro Forma Net Presentation Asset	Pro Forma Net Presentation Liability
Current Position				
Counterparties with offsetting positions	$86.9	$ 5.2	$81.7	$ -
Counterparties without offsetting positions - assets	5.3	-	5.3	-
Counterparties without offsetting positions - liabilities	-	-	-	-
	92.2	5.2	87.0	-
Long Term Position				
Counterparties with offsetting positions	34.2	2.4	31.8	-
Counterparties without offsetting positions - assets	0.7	-	0.7	-
Counterparties without offsetting positions - liabilities	-	-	-	-
	34.9	2.4	32.5	-
Total Derivatives				
Counterparties with offsetting positions	121.1	7.6	113.5	-
Counterparties without offsetting positions - assets	6.0	-	6.0	-
Counterparties without offsetting positions - liabilities	-	-	-	-
	$127.1	$ 7.6	$119.5	$ -

Our payment obligations in connection with substantially all of these hedging transactions are secured by a first priority lien in the collateral securing the Partnership's senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its senior secured lenders. Some of our hedges are futures contracts executed through a counterparty that clears the hedges through an exchange. The payment obligations on these futures are settled daily.

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net asset of $20.4 million as of June 30, 2016. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented. Our futures contracts that are cleared through an exchange are settled daily and do not require any credit adjustment.

The following tables reflect amounts recorded in Other Comprehensive Income ("OCI") and amounts reclassified from OCI to revenue and expense for the periods indicated:

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)			
Derivatives in Cash Flow	Three Months Ended June 30,		Six Months Ended June 30,	
Hedging Relationships	2016	2015	2016	2015
Commodity contracts	$ (60.2)	$ (3.6)	$ (53.5)	$ 27.0

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2016	2015	2016	2015
Revenues	$ 18.3	$ 21.4	$ 42.4	$ 34.9

Our consolidated earnings are also affected by the 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 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.

	Location of Gain	Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
Derivatives Not Designated as Hedging Instruments	Recognized in Income on Derivatives	2016	2015	2016	2015
Commodity contracts	Revenue	$(0.3)	$(4.0)	$1.6	$3.2

The following table shows the deferred gains (losses) included in accumulated OCI, which will be reclassified into earnings before income taxes through the end of 2019 based on valuations as of the balance sheet date:

	June 30, 2016	December 31, 2015
Commodity hedges, before tax (1)	$(9.3)	$ 86.7

(1) Includes deferred net gains of $1.3 million as of June 30, 2016 related to contracts that will be settled and reclassified to revenue over the next 12 months.

See Note 16 – Fair Value Measurements for additional disclosures related to derivative instruments and hedging activities.

Note 16 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities (“financial instruments”). Derivative financial instruments and contingent consideration related to business acquisitions are reported at fair value in our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost in our Consolidated Balance Sheets. The following are additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swaps, futures, option contracts and fixed-price forward commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. We have consistently applied these valuation techniques in all periods presented and we believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The fair values of our derivative instruments are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. The financial position of these derivatives at June 30, 2016, a net asset position of $20.4 million, reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive or pay in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net liability of $18.2 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 $56.9 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

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. Long-term debt is primarily the other financial instrument for which carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

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

We have a contingent consideration liability for APL’s previous acquisition of a gas gathering system and related assets, which is carried at fair value (see Note 4 – Business Acquisitions).

Fair Value Hierarchy

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

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

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

	June 30, 2016				
	Carrying	Fair Value			
	Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$55.0	$55.0	$ —	$52.2	$2.8
Liabilities from commodity derivative contracts (1)	34.6	34.6	—	33.0	1.6
TPL contingent consideration (2)	3.0	3.0	—	—	3.0
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	170.9	170.9	—	—	—
TRC Senior secured revolving credit facility	275.0	275.0	—	275.0	—
TRC term loan	157.6	157.0	—	157.0	—
Partnership's Senior secured revolving credit facility	55.0	55.0	—	55.0	—
Partnership's Senior unsecured notes	4,325.9	4,277.7	—	4,277.7	—

Partnership's accounts receivable securitization facility	225.0	225.0	—	225.0	—

	December 31, 2015				
	Carrying	Fair Value			
	Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$127.1	$127.1	$ —	$123.1	$4.0
Liabilities from commodity derivative contracts (1)	7.6	7.6	—	7.3	0.3
TPL contingent consideration (2)	3.0	3.0	—	—	3.0
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	140.2	140.2	—	—	—
TRC Senior secured revolving credit facility	440.0	440.0	—	440.0	—
TRC term loan	157.5	158.3	—	158.3	—
Partnership's Senior secured revolving credit facility	280.0	280.0	—	280.0	—
Partnership's Senior unsecured notes	4,884.0	4,192.0	—	4,192.0	—
Partnership's accounts receivable securitization facility	219.3	219.3	—	219.3	—

(1) The fair value of derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 15 – Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the

Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.
(2) See Note 4 – Business Acquisitions.
Additional Information Regarding Level 3 Fair Value Measurements Included in Our Consolidated Balance Sheets

We reported certain of our swaps and option contracts 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 swaps is determined using a discounted cash flow valuation technique based on a forward commodity basis curve. For these derivatives, the primary input to the valuation model is the forward commodity basis curve, which is based on observable or public data sources and extrapolated when observable prices are not available.

As of June 30, 2016, we had 20 commodity swap and option contracts categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are the forward natural gas curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

The fair value of the contingent consideration was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures. These probability-based inputs are not observable; therefore, the entire valuation of the contingent consideration is categorized in Level 3. Changes in the fair value of this liability are included in Other Income on the Consolidated Statements of Operations.

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

	Commodity Derivative Contracts Asset/(Liability)	Contingent Liability
Balance, December 31, 2015	$ 3.7	$ 3.0
New Level 3 instruments	1.1	-
Settlements included in revenues	(0.7)	-
Unrealized gain/(loss) included in OCI	(2.9)	-
Balance, June 30, 2016	$ 1.2	$ 3.0

For the six months ended June 30, 2016, we had no transfers of financial instruments out of Level 3 and into Level 2. Transfers relate to long-term over-the-counter swaps for natural gas and NGL products with deliveries for which observable market prices were available.

Note 17 – Contingencies

Legal Proceedings

Litigation related to TRC/TRP Merger

On December 16, 2015, two purported unitholders of TRP (the “State Court Plaintiffs”) filed a putative class action and derivative lawsuit challenging the TRC/TRP Merger against TRC, TRP (as a nominal defendant), TRP GP, the members of the board of TRP GP (the “TRP GP Board”) and Merger Sub (collectively, the “State Court Defendants”). This lawsuit is styled Leslie Blumberg et al. v. TRC Resources Corp., et al., Cause No. 2015-75481, in the 234th Judicial District Court of Harris County, Texas (the “State Court Lawsuit”). The State Court Plaintiffs amended the State Court Lawsuit on July 26, 2016.

The State Court Plaintiffs allege several causes of action challenging the TRC/TRP Merger. Generally, the State Court Plaintiffs allege that (i) the members of the TRP GP Board breached express and/or implied duties under the TRP partnership agreement and (ii) TRC, TRP GP, and Merger Sub aided and abetted in these alleged breaches of duties. The State Court Plaintiffs further allege, in general, that (a) the premium offered to TRP’s unitholders was inadequate, (b) the TRC/TRP Merger did not include a collar to protect TRP unitholders from decreases in TRC’s stock price, (c) the TRP GP Board agreed to contractual terms that allegedly may have dissuaded other potential acquirers from seeking to acquire TRP (including the “no-solicitation,” “matching rights,” and “termination fee” provisions), (d) the process leading up to the TRC/TRP Merger was unfair (e) the TRP GP Board had conflicts of interest due to

TRC's control of TRP GP (f) the TRP GP Conflicts Committee's financial advisor was conflicted and conducted flawed analyses, and (g) the joint proxy statement/prospectus filed in connection with the TRC/TRP Merger (the "Proxy") failed to disclose allegedly material information concerning, among other things, (i) the TRC and TRP projections included in the proxy, and (ii) the analyses conducted by the TRP GP Conflicts Committee's financial advisor in connection with the TRC/TRP Merger.

Based on these allegations, the State Court Plaintiffs seek damages and attorneys' fees. On February 26 and 29, 2016, the State Court Defendants filed general denials and asserted affirmative defenses.

The State Court Defendants cannot predict the outcome of this or any other lawsuits that might be filed subsequent to the date of the filing of this report, nor can the State Court Defendants predict the amount of time and expense that will be required to resolve such litigation. The State Court Defendants believe the State Court Lawsuit is without merit and intend to defend vigorously against this lawsuit and any other actions that challenge the TRC/TRP Merger.

On January 6 and 19, 2016, two additional purported unitholders of TRP (the "Federal Court Plaintiffs") filed two putative class action lawsuits challenging the disclosures made in connection with the TRC/TRP Merger against TRP and the members of the TRP GP Board (collectively the "Federal Court Defendants"). These lawsuits have been consolidated as In re Targa Resources Partners, L.P. Securities Litigation, Consolidated C.A. No. 4:16-cv-00041, in the United States District Court for the Southern District of Texas, Houston Division (the "Federal Court Lawsuits").

The Federal Court Plaintiffs alleged that (i) the Federal Court Defendants have violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and (ii) the members of the TRP GP Board have violated Section 20(a) of the Exchange Act. The Federal Court Plaintiffs alleged, in general, that the preliminary and definitive Proxy failed, among other things, to disclose allegedly material information concerning (i) the TRP GP Conflicts Committee's financial advisor's and TRC's financial advisor's analyses in connection with the TRC/TRP Merger, (ii) certain TRC and TRP projections, and (iii) the events leading up to the TRC/TRP Merger. The Federal Court Plaintiffs further alleged, in general, that (a) the premium offered to TRP's unitholders was inadequate, (b) the TRC/TRP Merger did not include a collar to protect TRP unitholders from decreases in TRC's stock price, (c) the TRP GP Board agreed to contractual terms that allegedly may have dissuaded other potential acquirers from seeking to acquire TRP (including the "no-solicitation," "matching rights," and "termination fee" provisions), (d) the process leading up to the TRC/TRP Merger was unfair and (e) the TRP GP Board has conflicts of interest due to TRC's control of the TRP GP.

Based on these allegations, the Federal Court Plaintiffs sought to enjoin the Federal Court Defendants from proceeding with or consummating the TRC/TRP Merger unless and until the Federal Court Defendants disclosed the allegedly omitted information summarized above. The Federal Court Plaintiffs also sought damages, attorneys' fees, and to have the TRC/TRP Merger rescinded.

One of the Federal Court Plaintiffs sought a Temporary Restraining Order ("TRO") to prevent the Federal Court Defendants from proceeding with the TRC/TRP vote and/or merger. On January 29, 2016, this Plaintiff was denied his request for a TRO. On April 20, 2016, the court dismissed the Federal Court Lawsuits without prejudice.

Environmental Proceedings

On June 18, 2015, the New Mexico Environment Department's Air Quality Bureau issued a Notice of Violation to Targa Midstream Services LLC for alleged violations of air emissions regulations related to emissions events that occurred at the Monument Gas Plant between June 2014 and December 2014. The Monument Gas Plant is operated by the Partnership and owned by Versado Gas Processors, L.L.C., which is a joint venture in which we own a 63% interest. The Partnership is in discussions with the New Mexico Environment Department to resolve the alleged violations. The Partnership anticipates that this matter could result in a monetary sanction in excess of $100,000 but less than $300,000.

We and the Partnership are also parties to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business.

Note 18 - Supplemental Cash Flow Information

	Six Months Ended June 30,	
	2016	2015
Cash:		
Interest paid, net of capitalized interest (1)	$ 142.2	$ 101.3
Income taxes paid, net of refunds	1.1	13.2
Non-cash investing activities:		
Deadstock commodity inventory transferred to property, plant and equipment	$ 16.9	$ 0.5
Impact of capital expenditure accruals on property, plant and equipment	(16.8)	(52.9)
Transfers from materials and supplies inventory to property, plant and equipment	0.9	1.6
Change in ARO liability and property, plant and equipment due to revised cash flow estimate	(9.1)	3.8
Non-cash financing activities:		
Reduction of Owner's Equity related to accrued dividends on unvested equity awards under share compensation arrangements	$ 4.9	$ 0.3
Debt additions and retirements related to exchange of TRP 6 % Notes for APL 6 % Notes	—	342.1
Allocation of Series A preferred stock net book value of BCF to additional paid-in capital	614.4	—
Accrued dividends of Series A preferred stock	22.9	—
Accrued deemed dividends of Series A preferred stock	6.5	—
Non-cash balance sheet movements related to the TRC/TRP Merger (see Note 2 - Basis of Presentation):		
Acquisition cost classified in the additional paid in capital	$ 4.5	$ —
Issuance of common stock	0.1	—
Additional paid-in capital	3,120.0	—
Accumulated other comprehensive income	55.7	—
Noncontrolling interests	(4,119.7)	—
Deferred tax liability	943.9	—
Non-cash balance sheet movements related to the Atlas Merger (see Note 4 - Business Acquisitions):		
Non-cash merger consideration - common units and replacement equity awards	$ —	$ 2,436.1
Non-cash merger consideration - common shares and replacement equity awards	—	1,013.7

Net non-cash balance sheet movements excluded from consolidated statements of cash flows	—	3,449.8
Net cash merger consideration included in investing activities	—	1,574.4
Total fair value of consideration transferred	$ —	$ 5,024.2

(1) Interest capitalized on major projects was $6.3 million and $5.5 million for the six months ended June 30, 2016 and 2015.

Note 19 – Compensation Plans

Long Term Incentive Plan

In connection with the TRC/TRP Merger, as of February 17, 2016, we assumed, adopted, and amended the Targa Resources Partners Long-Term Incentive Plan ("TRP LTIP"), and changed the name of the plan to the Targa Resources Corp. Equity Compensation Plan (as assumed, adopted and amended, the "Plan"), and we assumed all Partnership obligations associated with the Plan existing prior to its assumption and adoption by us. The only outstanding awards under the Plan at the time of the TRC/TRP Merger and immediately prior to the assumption and adoption of the Plan were performance units and certain phantom units of the Partnership. All such outstanding awards were converted at the effective time of the TRC/TRP Merger into comparable time-based restricted stock unit awards based on our common stock, which were assumed and adopted by us and continue to be outstanding and governed by the Plan.

On March 2, 2016, we filed a Registration Statement S-8 to register 800,000 shares of common stock issuable under the Plan. On May 26, 2016, we filed a Registration Statement S-8 to register an additional 300,000 shares of common stock issuable under the Plan.

The TRC/TRP Merger did not trigger the acceleration of any time-based vesting of any of the Partnership's outstanding long-term equity incentive compensation awards under the TRP LTIP. All outstanding performance unit awards previously granted under the TRP LTIP were converted and restated into comparable awards based on Targa's common shares. Specifically, each outstanding performance unit award was converted and restated, effective as of the effective time of the TRC/TRP Merger, into an award to acquire, pursuant to the same time-based vesting schedule and forfeiture and termination provisions, a comparable number of Targa common shares determined by multiplying the number of performance units subject to each award by the exchange ratio in the TRC/TRP Merger (0.62), rounded down to the nearest whole share, and the performance factor was eliminated. All amounts previously credited as distribution equivalent rights under any outstanding performance unit award continue to remain so credited and will be payable on the payment date set forth in the applicable award agreement, subject to the same time-based vesting schedule previously included in the performance unit award, but without application of any performance factor.

			Cash-Settled Performance Units Targa Resources Long-Term Incentive Plan		
	Equity-Settled Performance Units	Replacement Phantom Units	2015	2014	2013
Before conversion	675,745	349,451	192,390	119,900	139,700
After conversion	418,903	216,561	119,178	74,248	86,538

The February 17, 2016 conversion of equity-settled performance units and replacement phantom units outstanding to equity-settled performance shares and replacement phantom shares was considered modification of awards under ASC 718, Accounting for Stock-Based Compensation ("ASC 718"). The incremental change of $3.9 million in fair value between the original grant date fair value and the fair value as of February 17, 2016 will be recognized prospectively in general and administrative expense over the remaining service period of each award.

The February 17, 2016 conversion of outstanding cash-settled performance units to cash-settled restricted stock units was considered modification of awards under ASC 718. The incremental change in fair value between the original grant date fair value and the fair value as of February 17, 2016 resulted in recognition of additional compensation costs during the first quarter of 2016 of $4.8 million. The remaining compensation cost will be recognized in general and administrative expense over the remaining service period of each award.

On March 2, 2016, the Compensation Committee granted restricted stock units awards of 331,282 shares to executive management and employees under the Plan for the 2016 compensation cycle that will cliff vest three years from the grant date.

Note 20 — Segment Information

We operate in two primary segments (previously referred to as divisions): (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business).

Concurrent with the completion of the TRC/TRP Merger in the first quarter of 2016, management reevaluated our reportable segments and determined that our previously disclosed divisions are the appropriate level of disclosure for our reportable segments. The increase in activity within Field Gathering and Processing due to the Atlas mergers coupled with the decline in activity in our Gulf Coast region makes the disaggregation of Field Gathering and Processing and Coastal Gathering and Processing no longer warranted. Management also determined that further disaggregation of our Logistics and Marketing segment is no longer appropriate due to the integrated nature of the operations within our Downstream Business and its leadership by a consolidated executive management team. The Gathering and Processing division was previously disaggregated into two reportable segments — (a) Field Gathering and Processing and (b) Coastal Gathering and Processing. The Logistics and Marketing division (also referred to as the Downstream Business) was previously disaggregated into two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution.

Our Gathering and Processing segment includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing segment 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, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of our other operations, as well as transporting natural gas and NGLs.

Logistics and Marketing operations are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas, Lake Charles, Louisiana and Tacoma, Washington.

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin and mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. Elimination of inter-segment transactions are reflected in the corporate and eliminations column.

Reportable segment information is shown in the following tables:

	Three Months Ended June 30, 2016				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$158.7	$ 1,135.6	$18.6	$ —	$1,312.9
Fees from midstream services	124.6	146.1	—	—	270.7
	283.3	1,281.7	18.6	—	1,583.6
Intersegment revenues					
Sales of commodities	468.6	52.7	—	(521.3)	—
Fees from midstream services	1.8	4.4	—	(6.2)	—
	470.4	57.1	—	(527.5)	—
Revenues	$753.7	$ 1,338.8	$18.6	$ (527.5)	$1,583.6
Operating margin	$139.1	$ 141.8	$18.6	$ —	$299.5
Other financial information:					
Total assets (1)	$10,168.0	$ 2,644.4	$55.0	$ 132.7	$13,000.1
Goodwill	$393.0	$ —	$—	$ —	$393.0
Capital expenditures	$71.3	$ 42.7	$—	$ 0.9	$114.9

(1) Corporate assets at the segment level primarily include tax-related assets, cash and prepaids.

	Three Months Ended June 30, 2015		
	Other	Corporate	Total

	Gathering and Processing	Logistics and Marketing		and Eliminations	
Revenues					
Sales of commodities	$486.7	$ 892.3	$17.1	$ —	$1,396.1
Fees from midstream services	113.6	189.7	—	—	303.3
	600.3	1,082.0	17.1	—	1,699.4
Intersegment revenues					
Sales of commodities	270.5	47.6	—	(318.1)	—
Fees from midstream services	1.9	5.2	—	(7.1)	—
	272.4	52.8	—	(325.2)	—
Revenues	$872.7	$ 1,134.8	$17.1	$ (325.2)	$1,699.4
Operating margin	$144.7	$ 163.7	$17.1	$ —	$325.5
Other financial information:					
Total assets (1)	$10,676.5	$ 2,356.4	$132.3	$ 145.8	$13,311.0
Goodwill	$557.9	$ —	$—	$ —	$557.9
Capital expenditures	$147.5	$ 80.3	$—	$ 1.3	$229.1

(1) Corporate assets at the segment level primarily include tax-related assets, cash and prepaids.

	Six Months Ended June 30, 2016				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$269.0	$ 2,169.3	$45.7	$ —	$2,484.0
Fees from midstream services	240.4	301.6	—	—	542.0
	509.4	2,470.9	45.7	—	3,026.0
Intersegment revenues					
Sales of commodities	881.0	100.0	—	(981.0)	—
Fees from midstream services	3.9	8.5	—	(12.4)	—
	884.9	108.5	—	(993.4)	—
Revenues	$1,394.3	$ 2,579.4	$45.7	$ (993.4)	$3,026.0
Operating margin	$254.7	$ 298.5	$45.7	$ (0.1)	$598.8
Other financial information:					
Total assets (1)	$10,168.0	$ 2,644.4	$55.0	$ 132.7	$13,000.1
Goodwill	$393.0	$ —	$—	$ —	$393.0
Capital expenditures	$174.2	$ 115.9	$—	$ 1.7	$291.8

(1) Corporate assets at the segment level primarily include tax related assets, cash and prepaids.

	Six Months Ended June 30, 2015				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$707.3	$ 2,052.2	$38.8	$ —	$2,798.3
Fees from midstream services	185.6	395.2	—	—	580.8
	892.9	2,447.4	38.8	—	3,379.1
Intersegment revenues					
Sales of commodities	548.6	103.4	—	(652.0)	—
Fees from midstream services	3.8	9.7	—	(13.5)	—

	552.4	113.1	—	(665.5)	—
Revenues	$1,445.3	$2,560.5	$38.8	$ (665.5)	$3,379.1
Operating margin	$231.4	$355.4	$38.8	$ —	$625.6
Other financial information:					
Total assets (1)	$10,676.5	$2,356.4	$132.3	$ 145.8	$13,311.0
Goodwill	$557.9	$ —	$—	$ —	$557.9
Capital expenditures	$241.6	$141.0	$—	$ 2.3	$384.9
Business acquisition	$5,024.2	$ —	$—	$ —	$5,024.2

(1) Corporate assets at the segment level primarily include tax related assets, cash and prepaids.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Sales of commodities:				
Natural gas	$309.5	$443.5	$636.4	$745.6
NGL	923.5	854.0	1,708.9	1,884.7
Condensate	39.0	51.4	61.2	72.7
Petroleum products	22.3	30.1	31.8	56.5
Derivative activities	18.6	17.1	45.7	38.8
	1,312.9	1,396.1	2,484.0	2,798.3
Fees from midstream services:				
Fractionating and treating	31.5	54.7	61.6	104.5
Storage, terminaling, transportation and export	108.2	121.6	226.7	257.7
Gathering and processing	114.0	105.7	219.0	174.1
Other	17.0	21.3	34.7	44.5
	270.7	303.3	542.0	580.8
Total revenues	$1,583.6	$1,699.4	$3,026.0	$3,379.1

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Reconciliation of operating margin to net income (loss):				
Operating margin	$ 299.5	$ 325.5	$ 598.8	$ 625.6
Depreciation and amortization expenses	(186.1)	(163.9)	(379.6)	(282.5)
General and administrative expenses	(47.0)	(49.2)	(92.2)	(91.7)
Goodwill impairment	-	-	(24.0)	-
Interest expense, net	(71.4)	(67.6)	(124.3)	(121.7)
Other, net	(7.9)	(6.2)	10.9	(39.9)
Income tax expense	(1.7)	(14.8)	(4.8)	(30.1)
Net income (loss)	$ (14.6)	$ 23.8	$ (15.2)	$ 59.7

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, 2015 ("Annual Report") and our Current Report on Form 8-K filed with the Securities and Exchange Commission ("SEC") on May 23, 2016, as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q. However, note that our filings for prior year include a delineation of Partnership and Non-Partnership activities which is no longer relevant as a result of the February 17, 2016 merger of TRC and TRP.

Overview

Targa Resources Corp. (NYSE: TRGP) is a publicly traded Delaware corporation formed in October 2005. On February 17, 2016, TRC completed the previously announced transactions contemplated by the Agreement and Plan of Merger (the "TRC/TRP Merger Agreement" or "Buy-in Transaction"), dated November 2, 2015, by and among TRC, TRP, the general partner of TRP and Spartan Merger Sub LLC, a subsidiary of TRC ("Merger Sub") pursuant to which TRC acquired indirectly all of the outstanding TRP common units that TRC and its subsidiaries did not already own. Upon the terms and conditions set forth in the TRC/TRP Merger Agreement, Merger Sub merged with and into TRP (the "TRC/TRP Merger"), with TRP continuing as the surviving entity and as a subsidiary of TRC. Following the closing of the TRC/TRP Merger, TRC owns all of the outstanding TRP common units.

Pursuant to the TRC/TRP Merger Agreement, we agreed to cause the TRP common units to be delisted from the New York Stock Exchange ("NYSE") and deregistered under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). As a result of the completion of the TRC/TRP Merger, the TRP common units are no longer publicly traded. The 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") remain outstanding as limited partner interests in TRP and continue to trade on the NYSE under the symbol "NGLS PRA."

As we continue to control the Partnership, the change in our ownership interest as a result of the TRC/TRP Merger was accounted for as an equity transaction which is reflected in our Consolidated Balance Sheet as a reduction of noncontrolling interests and a corresponding increase in common stock and additional paid-in capital. The TRC/TRP merger is a taxable exchange resulting in a book/tax difference in the basis of the underlying assets acquired (our investment in TRP). A deferred tax liability of approximately $950 million has been recorded, computed as $9.0 billion book basis in excess of $6.5 billion tax basis at our statutory tax rate of 37.11%.

Our Operations

We are engaged in the business of:

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

To provide these services, we operate in two primary segments (previously referred to as divisions): (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business).

Concurrent with the TRC/TRP Merger, management reevaluated our reportable segments. The Gathering and Processing division was previously disaggregated into two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing. The Logistics and Marketing division (also referred to as the Downstream Business) was previously disaggregated into two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution. Management determined that our previously disclosed divisions are the appropriate level of disclosure for our reportable segments. The increase in activity within Field Gathering and Processing due to the Atlas mergers coupled with the decline in activity in our Gulf Coast region makes the disaggregation of Field Gathering and Processing and Coastal Gathering and Processing no longer warranted. Management also determined that further disaggregation of our Logistics and Marketing segment is no longer appropriate due to the integrated nature of the operations within our Downstream Business and its leadership by a consolidated executive management team.

Our Gathering and Processing segment includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma

Basins in Oklahoma and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing segment 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, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of our other operations, as well as transporting natural gas and NGLs.

The Logistics and Marketing operations are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas, Lake Charles, Louisiana and Tacoma, Washington.

Other contains the results (including any hedge ineffectiveness) of our commodity derivative activities which are included in operating margin.

Volatility of Commodity Prices

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development and production of new oil and natural gas reserves. Drilling and production activity generally decreases as crude oil and natural gas prices decrease below commercially acceptable levels. Prices of oil and natural gas have been historically volatile, and we expect this volatility to continue. Our operations are affected by the level of crude, natural gas and NGL prices, the relationship among these prices and related reduced activity levels from our customers. Beginning in the fourth quarter of 2014, oil and natural gas prices declined significantly primarily due to global supply and demand imbalances. Oil and natural gas prices continued to decline in 2015 and have remained depressed in 2016. The duration and magnitude of the decline in market prices cannot be predicted.

2016 Developments

Logistics and Marketing Segment Expansion

Cedar Bayou Fractionator Train 5

In June 2016, we commissioned an additional fractionator, Train 5, at our 88%-owned Cedar Bayou Fractionator ("CBF") in Mont Belvieu, Texas. This expansion added 100 MBbl/d of fractionation capacity at CBF, and is fully integrated with our existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as our LPG export terminal at Galena Park on the Houston Ship Channel. The gross cost of Train 5 was approximately $328 million (our net cost was approximately $297 million).

Channelview Splitter

On December 27, 2015, we and Noble entered into the Splitter Agreement under which we will build and operate a 35,000 barrel per day crude and condensate splitter at our Channelview Terminal on the Houston Ship Channel ("Channelview Splitter"). The Channelview Splitter will have the capability to split approximately 35,000 barrels per day of crude and condensate into its various components, including naphtha, kerosene, gas oil, jet fuel, and liquefied petroleum gas and will provide segregated storage for the crude, condensate and components. The Channelview Splitter is expected to be completed by early 2018, and has an estimated total cost of approximately $140 million. As contemplated by the December 2014 Agreement, the Splitter Agreement completes and terminates the December 2014 Agreement, while retaining our economic benefits from that agreement.

Gathering and Processing Segment Expansion

Permian Basin Buffalo Plant

In April 2016, we commenced commercial operations of a new 200 MMcf/d cryogenic processing plant, known as the Buffalo Plant, in our WestTX system. This project also included the laying of a new high pressure gathering line into Martin and Andrews counties of Texas. Total net growth capital expenditures for the Buffalo Plant were approximately $101 million. The addition of the Buffalo Plant will enable us to meet increasing production from our joint venture partner in WestTX, Pioneer (the largest active driller in the Spraberry and Wolfberry Trends), and from other producers in the area.

Eagle Ford Shale Natural Gas Processing Joint Venture

In October 2015, we announced that entered into joint venture agreements with Sanchez Energy Corporation (“Sanchez”) to construct a new 200MMcf/d cryogenic natural gas processing plant in La Salle County, Texas (the “Raptor Plant”) and approximately 45 miles of associated pipelines. We own a 50% interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect Sanchez's Catarina gathering system to the plant. We hold a portion of the transportation capacity on the pipeline, and the gathering joint venture receives fees for transportation. We expect to invest approximately $125 million of growth capital expenditures related to the joint ventures.

The Raptor Plant will accommodate the growing production from Sanchez’s premier Eagle Ford Shale acreage position in Dimmit, La Salle and Webb Counties, Texas and from other third party producers. The plant and high pressure gathering lines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We will manage construction and operations of the plant and high pressure gathering lines, and the plant is expected to begin operations in early 2017. Prior to the plant being placed in-service, we benefit from Sanchez natural gas volumes that are processed at our Silver Oak facilities in Bee County, Texas.

In addition to the major projects in process noted above, we potentially have other growth capital expenditures in 2016 related to the continued build out of our gathering and processing infrastructure and logistics capabilities. In the current environment, we will continue to evaluate these potential projects based on return profile, capital requirements and strategic need and may choose to defer projects depending on expected activity levels.

Financing Activities

On February 17, 2016, we completed the TRC/TRP Merger, and issued 104,525,775 shares of our common stock to unitholders of the common units of the Partnership in exchange for all of the 168,590,009 outstanding common units of the Partnership that we did not previously own.

In March 2016, through a private placement, we issued 965,100 newly authorized shares of Series A Preferred Stock (the “Series A Preferred”) with detachable warrants for $1,030 per share. The Series A Preferred can be redeemed in whole or in part at our option after five years, and can be converted into our common stock in 2028 by the holders of the Series A Preferred or, under certain circumstances, by us. The Series A Preferred investors also received warrants exercisable into 13,550,004 shares of our common stock with an exercise price of $18.88 per common share (the “Series A Warrants”) and warrants exercisable into 6,533,727 shares of our common stock with an exercise price of $25.11 per common share (the “Series B Warrants” and together with the Series A Warrants, the “Warrants”). The Warrants have a seven year term from the date of issuance and are exercisable starting in September 2016. On June 30, 2016, we filed a prospectus supplement to our Registration Statement on Form S-3 filed with the SEC on May 23, 2016, which registered the maximum amount of common shares issuable upon exercise of the Warrants. For accounting purposes, net proceeds of $970.3 million (net of $23.8 million transaction fees) are allocated based on relative fair values to Preferred ($787.9 million) and Warrants ($182.4 million), included in additional paid-in capital.

Given that our share price increased between the signing and closing date of our Series A Preferred Stock issuance, the inherent nondetachable conversion feature, referred to as a beneficial conversion feature (“BCF”), was in the money at the issuance date. As such, we allocated a portion of the proceeds ($614.4 million) initially allocated to Series A Preferred to the intrinsic value of the BCF as additional paid-in capital to give effect for the beneficial conversion feature. We record the accretion of the $614.4 million preferred stock discount attributable to the BCF as a deemed dividend using the effective yield method over the twelve year period prior to the effective date of the holders' conversion right. We used the net proceeds from this Series A Preferred private placement to repay indebtedness, for open market senior note repurchases and for general corporate purposes. During the six months ended June 30, 2016, we recorded deemed dividends of $6.5 million. We have the right to redeem the Series A Preferred beginning after year five. As such, we can effectively mitigate or limit the Series A Preferred holders' ability to benefit from the conversion right by paying either a $96.5 million (10%) redemption premium in year six or a $48.3 million (5%) redemption premium in years seven through twelve. In either case, the redemption premium would be significantly less than the $614.4 million BCF required to be recognized under GAAP.

During the six months ended June 30, 2016, we repurchased a portion of the outstanding senior notes of TRP on the open market, paying $534.3 million plus accrued interest to repurchase $559.2 million of the notes. The repurchases resulted in a $21.4 million net gain, which included the write-off of $3.5 million in related debt issuance costs. We or TRP may retire or purchase various series of TRP's outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

In May 2016, we entered into an Equity Distribution Agreement under the May 2016 Shelf (the "May 2016 EDA") with Barclays Capital Inc., Capital One Securities Inc., Citigroup Global Markets Inc., Deutsche Bank Securities Inc., Goldman, Sachs & Co., Jefferies LLC, J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc., and Wells Fargo Securities, LLC, as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $500 million of our common stock. The common stock available for sale under the May 2016 EDA were validly registered pursuant to the registration statement on Form S-3 filed on May 23, 2016. During the three months ended June 30, 2016, we issued 5,105,652 shares of common stock under the May 2016 EDA, receiving net proceeds of $215.1 million. In July 2016, we issued 781,262 shares of common stock for which we received proceeds of $32.7 million, net of commissions and fees, pursuant to the May 2016 EDA.

Recent Accounting Pronouncements

Revenue from Contracts with Customers

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

With the issuance in August 2015 of ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, the revenue recognition standard is effective for the annual period beginning after December 15, 2017, and for annual and interim periods thereafter. Earlier adoption is permitted for annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. We must retroactively apply the new revenue recognition standard to transactions in all prior periods presented, but will have a choice between either (1) restating each prior period presented or (2) presenting a cumulative effect adjustment in the period the amendment is adopted.

In March 2016, the FASB issued ASU 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations. The amendments in this update improve the operability and understandability of the implementation guidance on principal versus agent considerations, including clarifying that an entity should determine whether it is a principal or an agent for each specified good or service promised to a customer. These amendments are effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2017, with early adoption permitted.

In April 2016, the FASB issued ASU 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing. These amendments clarify the guidance on identification of performance obligations and licensing. The amendments include that entities do not have to decide if goods and services are performance obligations if they are considered immaterial in the context of a contract. Entities are also permitted to account for the shipping and handling that takes place after the customer has gained control of the goods as actions to fulfill the contract rather than separate services. In order to identify a performance obligation in a customer contract, an entity has to determine whether the goods or services are distinct, and ASU No. 2016-10 clarifies how the determination can be made.

In May 2016, the FASB issued ASU 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients. These amendments address certain implementation issues related to assessing collectability, presentation of sales taxes, noncash consideration, and completed contracts and contract modifications at transition, and also provide additional practical expedients.

We expect to adopt these updates in their entirety on January 1, 2018, and are continuing to evaluate the impact on our revenue recognition practices.

Consolidation

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. The amendments are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. The amendments are effective for us in 2016 with no impact on our consolidated financial statement or results of operations.

Presentation of Debt Issuance Costs

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. The amendments in this update require that debt issuance costs related to a recognized debt liability (other than line-of-credit or other revolving credit facilities) be presented in the Consolidated Balance Sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This update dealt solely with financial statement display matters; recognition and measurement of debt issuance costs were unaffected. We adopted the amendments on January 1, 2016 and have reclassified unamortized debt issuance costs of $42.7 million on our Consolidated Balance Sheet as of December 31, 2015 from Other long-term assets to Long-term debt to conform to current year presentation. Our Consolidated Balance Sheet as of June 30, 2016 has $35.2 million in unamortized debt issuance costs classified in Long-term debt.

Leases

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We expect to adopt the amendments in the first quarter of 2019 and are currently evaluating the impacts of the amendments to our financial statements and accounting practices for leases.

Share-Based Compensation

In March 2016, the FASB issued ASU 2016-09, Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. The amendments in this update provides, among other things, that (1) all excess tax benefits and tax deficiencies (including tax benefits of dividends on share-based payment awards) should be recognized as income tax expense or benefit in the income statement with the tax effects of exercised or vested awards treated as discrete items in the reporting period in which they occur and recognition of excess tax benefits regardless of whether the benefit reduces taxes payable in the current period; (2) excess tax benefits should be classified along with other income tax cash flows as an operating activity; (3) an entity can make an entity-wide accounting policy election to either estimate the number of awards that are expected to vest or account for forfeitures when they occur; (4) the threshold to qualify for equity classification permits withholding up to the maximum statutory tax rates in the applicable jurisdictions; and (5) cash paid by an employer when directly withholding shares for tax-withholding purposes should be classified as a financing activity on the statement of cash flows.

We adopted the applicable amendments in the second quarter of 2016 and have applied the guidance as of January 1, 2016. Amendments related to the timing of when excess tax benefits and deficiencies are recognized, minimum statutory withholding requirements, and forfeitures have been applied using a modified retrospective transition method but resulted in no cumulative effect adjustment to equity. The amendment related to the presentation of employee taxes paid on the statement of cash flows when an employer withholds shares to meet the minimum statutory withholding requirement had no impact as we previously classified these payments as a financing activity and continue to do so. The amendment requiring recognition of excess tax benefits and tax deficiencies in the income statement has been applied prospectively. We have elected to apply the amendment related to the presentation of excess tax benefits and deficiencies on the statement of cash flows on a prospective basis and prior periods have not been adjusted. We recognized $2.4 million of excess tax deficiencies in income tax expense for the six months ended June 30, 2016, which includes $0.5 million attributable to the three months ended March 31, 2016. Our diluted earnings per share calculation has been adjusted for the three and six months ended June 30, 2016, to exclude windfall tax benefits in assumed proceeds under the treasury stock method. In addition, we elected to account for forfeitures as they occur.

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued ASU 2016-13, Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. These amendments change the measurement of credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The amendments in this update affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. The amendments replace the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to inform credit loss estimates. We expect to adopt this guidance on January 1, 2019, and are continuing to evaluate the impact on our measurement of credit losses.

How We Evaluate Our Operations

The following discussion of how we evaluate our operations reflects the impact of the February 17, 2016 closing of the TRC/TRP Merger. Our non-GAAP financial measures have been revised accordingly and prior year pro forma non-GAAP measures have been provided for comparative purposes.

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

Our profitability is also impacted by fee-based revenues. Our growth strategy, based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, has increased the percentage of our revenues that are fee-based. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

Our profitability is impacted by our ability to add new sources of natural gas supply and crude oil supply to offset the natural decline of existing volumes from oil and natural gas wells that are connected to our gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production, as well as by capturing crude oil and natural gas supplies currently gathered by third-parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to our Downstream Business’ fractionation facilities. We fractionate NGLs generated by our gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities.

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

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

Operating Expenses

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

Capital Expenditures

Capital projects associated with growth and maintenance projects are closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval.

Gross Margin

We define gross margin as revenues less product purchases. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program.

Gathering and Processing segment gross margin consists primarily of revenues from the sale of natural gas, condensate, crude oil and NGLs and fee revenues related to natural gas and crude oil gathering and services, less producer payments and other natural gas and crude oil purchases.

Logistics and Marketing segment gross margin consists primarily of

- service fee revenues (including the pass-through of energy costs included in fee rates),
- system product gains and losses, and
- NGL and natural gas sales less NGL and natural gas purchases, transportation costs and the net inventory change.

The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

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

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

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

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definitions of gross margin and operating margin may not be comparable with 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 our decision-making processes.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) available to TRC before: interest; income taxes; depreciation and amortization; impairment of goodwill; gains or losses on debt repurchases, redemptions, amendments, exchanges and early debt extinguishments and asset disposals; risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL merger; non-cash compensation on equity grants; transaction costs related to business acquisitions; net income attributable to TRP preferred limited partners; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests, change in contingent consideration and the noncontrolling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and pay dividends to our investors.

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

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

Distributable Cash Flow

We define distributable cash flow as Adjusted EBITDA less distributions to TRP preferred limited partners, cash interest expense on debt obligations, current cash tax expenses and maintenance capital expenditures (net of any reimbursements of project costs). This measure includes the impact of noncontrolling interests on the prior adjustment items.

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by our board of directors) 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 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 a non-GAAP financial measure. The GAAP measure most directly comparable to distributable cash flow is net income (loss) attributable to TRC. Distributable cash flow should not be considered as an alternative to GAAP net income (loss) available to common and preferred shareholders. It has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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

Our Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measures used by management to the most directly comparable GAAP measures for the periods indicated, with 2015 amounts presented for comparative purposes.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of TRC gross margin and operating margin to net income (loss) attributable to TRC:				
Gross margin	$ 438.4	$ 471.3	$ 869.8	$ 892.5
Operating expenses	(138.9)	(145.8)	(271.0)	(266.9)
Operating margin	299.5	325.5	598.8	625.6
Depreciation and amortization expenses	(186.1)	(163.9)	(379.6)	(282.5)
General and administrative expenses	(47.0)	(49.2)	(92.2)	(91.7)
Goodwill impairment	—	—	(24.0)	—
Interest expense, net	(71.4)	(67.6)	(124.3)	(121.7)
Income tax expense	(1.7)	(14.8)	(4.8)	(30.1)
Gain (loss) on sale or disposition of assets	—	0.1	(0.9)	0.2
Gain (loss) from financing activities	(3.3)	(3.8)	21.4	(12.9)
Other, net	(4.6)	(2.5)	(9.6)	(27.2)
Net income (loss)	(14.6)	23.8	(15.2)	59.7
Less: Net income (loss) attributable to noncontrolling interests	8.6	8.6	10.7	41.1
Net income (loss) attributable to TRC	$ (23.2)	$ 15.2	$ (25.9)	$ 18.6

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ (23.2)	$ 15.2	$ (25.9)	$ 18.6
Impact of TRC/TRP Merger on NCI	—	1.1	(3.9)	28.6
Income attributable to TRP preferred limited partners	2.8	—	5.6	—
Interest expense, net	71.4	67.6	124.3	121.7
Income tax expense	1.7	14.8	4.8	30.1
Depreciation and amortization expenses	186.1	163.9	379.6	282.5
Goodwill impairment	—	—	24.0	—
(Gain) loss on sale or disposition of assets	—	(0.1)	0.9	(0.2)
(Gain) loss from financing activities	3.3	3.8	(21.4)	12.9
(Earnings) loss from unconsolidated affiliates	4.4	1.5	9.2	(0.5)

Distributions from unconsolidated affiliates and preferred partner interests, net	3.0	6.9	8.8	10.4
Compensation on equity grants	7.2	6.5	15.2	12.4
Transaction costs related to business acquisitions	—	1.0	—	26.8
Risk management activities	6.6	24.8	12.6	24.2
Noncontrolling interests adjustments (1)	(6.2)	(4.6)	(12.1)	(8.5)
TRC Adjusted EBITDA	$ 257.1	$ 302.4	$ 521.7	$ 559.0
Distributions to TRP preferred limited partners	(2.8)	—	(5.6)	—
Interest expenses on debt obligations (2)	(65.9)	(66.2)	(135.6)	(117.9)
Current cash tax expense (3)	—	—	—	—
Maintenance capital expenditures	(20.2)	(27.6)	(35.2)	(46.6)
Noncontrolling interests adjustments of maintenance capex	1.4	2.0	2.2	3.6
Distributable Cash Flow	$ 169.6	$ 210.6	$ 347.5	$ 398.1

(1) Noncontrolling interest portion of depreciation and amortization expenses.
(2) Excludes amortization of interest expense.
(3) Includes adjustment to account for differences between cash and book taxes.

Consolidated Results of Operations

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

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	2016 vs. 2015		Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	2016 vs. 2015	
	($ in millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 1,312.9	$ 1,396.1	$ (83.2)	(6 %)	$ 2,484.0	$ 2,798.3	$ (314.3)	(11 %)
Fees from midstream services	270.7	303.3	(32.6)	(11 %)	542.0	580.8	(38.8)	(7 %)
Total revenues	1,583.6	1,699.4	(115.8)	(7 %)	3,026.0	3,379.1	(353.1)	(10 %)
Product purchases	1,145.2	1,228.1	(82.9)	(7 %)	2,156.2	2,486.6	(330.4)	(13 %)
Gross margin (1)	438.4	471.3	(32.9)	(7 %)	869.8	892.5	(22.7)	(3 %)
Operating expenses	138.9	145.8	(6.9)	(5 %)	271.0	266.9	4.1	2 %
Operating margin (2)	299.5	325.5	(26.0)	(8 %)	598.8	625.6	(26.8)	(4 %)
Depreciation and amortization expenses	186.1	163.9	22.2	14 %	379.6	282.5	97.1	34 %
General and administrative expenses	47.0	49.2	(2.2)	(4 %)	92.2	91.7	0.5	1 %
Goodwill impairment	—	—	—	—	24.0	—	24.0	—
Other operating (income) expenses	0.1	—	0.1	—	1.1	0.6	0.5	83 %
Income from operations	66.3	112.4	(46.1)	(41 %)	101.9	250.8	(148.9)	(59 %)
Interest expense, net	(71.4)	(67.6)	(3.8)	(6 %)	(124.3)	(121.7)	(2.6)	(2 %)
Equity earnings (loss)	(4.4)	(1.5)	(2.9)	(193 %)	(9.2)	0.5	(9.7)	NM
Gain (loss) from financing activities	(3.3)	(3.8)	0.5	13 %	21.4	(12.9)	34.3	266 %
Other income (expense)	(0.1)	(0.9)	0.8	89 %	(0.2)	(26.9)	26.7	99 %
Income tax (expense) benefit	(1.7)	(14.8)	13.1	89 %	(4.8)	(30.1)	25.3	84 %
Net income (loss)	(14.6)	23.8	(38.4)	(161 %)	(15.2)	59.7	(74.9)	(125 %)
Less: Net income (loss) attributable to noncontrolling interests	8.6	8.6	—	—	10.7	41.1	(30.4)	(74 %)
Net income (loss) attributable to Targa Resources Corp.	(23.2)	15.2	(38.4)	(253 %)	(25.9)	18.6	(44.5)	(239 %)
Dividends on Series A preferred stock	22.9	—	22.9	—	26.7	—	26.7	—
Deemed dividends on Series A preferred stock	6.5	—	6.5	—	6.5	—	6.5	—
Net income (loss) attributable to common shareholders	$ (52.6)	$ 15.2	$ (67.8)	NM	$ (59.1)	$ 18.6	$ (77.7)	NM

Financial and operating data:								
Financial data:								
Adjusted EBITDA (3)	257.1	302.4	(45.3)	(15 %)	521.7	559.0	(37.3)	(7 %)
Distributable cash flow (4)	169.6	210.6	(41.0)	(19 %)	347.5	398.1	(50.6)	(13 %)
Capital expenditures	114.9	229.1	(114.2)	(50 %)	291.8	384.9	(93.1)	(24 %)
Business acquisitions	—	—	—	—	—	5,024.2	(5,024.2)	(100%)
Operating statistics:								
Crude oil gathered, MBbl/d	105.2	106.2	(1.0)	(1 %)	105.2	103.7	1.5	1 %
Plant natural gas inlet, MMcf/d (5) (6) (7)	3,523.3	3,528.4	(5.1)	—	3,464.6	3,016.6	448.0	15 %
Gross NGL production, MBbl/d (7)	321.0	290.6	30.4	10 %	302.8	242.7	60.1	25 %
Export volumes, MBbl/d (8)	181.3	164.3	17.0	10 %	181.2	177.9	3.3	2 %
Natural gas sales, BBtu/d (6) (7) (9)	1,958.4	1,998.8	(40.4)	(2 %)	1,966.5	1,614.2	352.3	22 %
NGL sales, MBbl/d (7) (9)	515.8	494.9	20.9	4 %	531.8	502.2	29.6	6 %
Condensate sales, MBbl/d (7)	11.4	11.6	(0.2)	(1 %)	10.4	8.7	1.7	20 %

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

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

(3) Adjusted EBITDA is net income (loss) available to TRC before: interest; income taxes; depreciation and amortization; impairment of goodwill; gains or losses on debt repurchases, redemptions, amendments, exchanges and early debt extinguishments and asset disposals; risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL merger; non-cash compensation on equity grants; transaction costs related to business acquisitions; net income attributable to TRP preferred limited partners; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests, change in contingent consideration and the noncontrolling interest portion of depreciation and amortization expenses. This is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations.”

(4) Distributable cash flow is Adjusted EBITDA less distributions to TRP preferred limited partners, cash interest expense on debt obligations, current cash tax expenses and maintenance capital expenditures (net of any reimbursements of project costs). This measure includes the impact of noncontrolling interests on the prior adjustment items. This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."
(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(7) These volume statistics are presented with the numerator as the total volume sold during the quarter and the denominator as the number of calendar days during the quarter.
(8) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine terminal that are destined for international markets.
(9) Includes the impact of intersegment eliminations.

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

The decrease in revenues was primarily due to lower commodity prices ($116.8 million) and decreased fee-based and other revenues ($37.1 million) from lower fractionation and export fees, partially offset by increased NGL sales volumes ($36.1 million).

Lower commodity prices brought a commensurate reduction in product purchases, partially offset by increased NGL purchases.

Gathering and Processing operating margin and gross margin decreased primarily due to lower commodity prices. Logistics and Marketing operating margin and gross margin decreased due to the realization in 2015 of contract renegotiation fees, lower LPG export margin, lower fractionation margin and lower terminaling and storage throughput. 2015 results included the partial recognition of renegotiated commercial arrangements related to our crude and condensate splitter project. Lower operating expenses are due to the cost savings generated throughout our operating areas. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expenses primarily reflects the impact of growth investments from system expansions including the Buffalo Plant, the Edwards Plant, compressor stations and pipelines.

Lower general and administrative expenses in 2016 reflect operational synergies, including integrating TPL into Targa's insurance program.

The increase in net interest expense in 2016 reflects $3.9 million of non-cash interest expense from the change in estimated redemption value of the mandatorily redeemable preferred interest for the three months ended June 30, 2016.

During the three months ended June 30, 2016, we repurchased $203.7 million of debt in open market purchases, which generated a loss of $3.3 million.

The increase in preferred dividends is due to the issuance of preferred stock on March 16, 2016.

Net income attributable to noncontrolling interests was flat. Distributions for the three months ended June 30, 2016 for the TRP's Preferred Units issued in November 2015 were $2.8 million, offset by lower earnings in 2016 at our joint ventures and the elimination of net income attributable to noncontrolling interests in TRP resulting from the TRC/TRP Merger in February 2016, in which TRC acquired indirectly all the outstanding TRP common units that TRC and its subsidiaries did not already own.

The decrease in income tax expense in 2016 is due to net operating loss deferred tax benefits arising from higher tax depreciation expense at TRC as a result of the TRP Merger.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

The decrease in revenues was primarily due to lower commodity prices ($625.5 million), partially offset by the favorable impact of inclusion of two additional months of operations of TPL during 2016 ($270.1 million). Additionally, fee-based and other revenues decreased due to lower fractionation and export fees, partially offset by the impact of an additional two months of TPL’s fee revenue in 2016 ($40.9 million).

Lower commodity prices brought a commensurate reduction in product purchases, partially offset by the inclusion of two additional months of operations from TPL in 2016 ($137.5 million).

The lower operating margin and gross margin in 2016 were attributable to the realization in 2015 of contract renegotiation fees, lower LPG export margin, lower fractionation margin, lower terminaling and storage throughput, significantly lower commodity prices and lower throughput volumes on our gathering systems. These declines were partially offset by the inclusion of TPL operations for an additional two months in 2016. 2015 results included the partial recognition of renegotiated commercial arrangements related to our crude and condensate splitter project. Operating expenses were relatively flat compared with 2015 due to the inclusion of TPL’s operations for an additional two months in 2016, offset by to a continued focused cost reduction effort throughout our operating areas. See “—Results of Operations—By Reportable Segment” for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expenses is primarily due to an additional two months of TPL operations in 2016, as well as growth investments from other system expansions including the Buffalo Plant, the Edwards Plant, compressor stations and pipelines.

General and administrative expenses, which include TPL operations for an additional two months in 2016, reflect operational synergies, including integrating TPL into Targa’s insurance program.

During 2016, we recognized an additional impairment of goodwill of $24.0 million to finalize the $290.0 million provisional impairment recorded during the fourth quarter of 2015.

The increase in net interest expense primarily reflects higher interest expense in 2016 from an increase in borrowings resulting from the September 2015 issuance of $600.0 million of 6¾% Senior Notes, partially offset by $534.3 million of open market debt repurchases during the six months ended June 30, 2016 and $14.6 million of non-cash interest income from the change in estimated redemption value of the mandatorily redeemable preferred interest for the six months ended June 30, 2016.

The decrease in equity earnings (loss) is due to lower operating results from GCF and the inclusion of an additional two months of equity losses from the T2 Joint Ventures.

Other expense in 2015 was primarily attributable to non-recurring transaction costs relate to the Atlas mergers.

During the six months ended June 30, 2016, we repurchased $534.3 million of debt in open market purchases, which generated a net gain of $21.4 million.

The decrease in income tax expense in 2016 is due to net operating loss deferred tax benefits arising from higher tax depreciation expense at TRC as a result of the TRP Merger.

The decrease in net income attributable to noncontrolling interests was primarily attributable to the TRC/TRP Merger in February 2016 and lower earnings in 2016 at our joint ventures, partially offset by $5.6 million of distributions for the six months ended June 30, 2016 for the TRP's Preferred Units issued in November 2015.

The increase in preferred dividends is due to the issuance of preferred stock on March 16, 2016.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Consolidated Operating Margin

	(In millions)									
Three Months Ended:										
June 30, 2016	$	139.1	$	141.8	$	18.6	$	-	$	299.5
June 30, 2015		144.7		163.7		17.1		-		325.5
Six Months Ended:										
June 30, 2016	$	254.7	$	298.5	$	45.7	$	(0.1)	$	598.8
June 30, 2015		231.4		355.4		38.8		-		625.6

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Gathering and Processing Segment

	Three Months Ended June 30, 2016	2015	2016 vs. 2015		Six Months Ended June 30, 2016	2015	2016 vs. 2015	
Gross margin	$ 222.4	$ 232.6	$ (10.2)	(4 %)	$ 416.5	$ 384.8	$ 31.7	8 %
Operating expenses	83.3	87.9	(4.6)	(5 %)	161.8	153.4	8.4	5 %
Operating margin	$ 139.1	$ 144.7	$ (5.6)	(4 %)	$ 254.7	$ 231.4	$ 23.3	10 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
SAOU (4)	259.2	237.7	21.5	9 %	251.3	227.1	24.2	11 %
WestTX (5)	493.3	433.2	60.1	14 %	477.1	285.5	191.6	67 %
Sand Hills	135.8	171.5	(35.7)	(21%)	143.4	165.0	(21.6)	(13 %)
Versado	168.8	185.6	(16.8)	(9 %)	174.4	179.5	(5.1)	(3 %)
Total Permian	1,057.1	1,028.0	29.1		1,046.2	857.1	189.1	
SouthTX (5)	265.4	150.9	114.5	76 %	220.5	100.0	120.5	121%
North Texas	327.5	356.1	(28.6)	(8 %)	327.5	358.0	(30.5)	(9 %)
SouthOK (5)	470.7	487.2	(16.5)	(3 %)	464.3	329.6	134.7	41 %
WestOK (5)	445.6	597.4	(151.8)	(25%)	466.3	405.4	60.9	15 %
Total Central	1,509.2	1,591.6	(82.4)		1,478.6	1,193.0	285.6	
Badlands (6)	51.2	46.8	4.4	9 %	52.5	44.5	8.0	18 %
Total Field	2,617.5	2,666.4	(48.9)		2,577.3	2,094.6	482.7	
Coastal	905.8	862.2	43.6	5 %	887.2	922.0	(34.8)	(4 %)
Total	3,523.3	3,528.6	(5.3)	0 %	3,464.5	3,016.6	447.9	15 %
Gross NGL production, MBbl/d (3)								
SAOU (4)	32.2	27.7	4.5	16 %	30.7	26.5	4.2	16 %
WestTX (5)	61.9	50.5	11.4	23 %	57.2	33.2	24.0	72 %
Sand Hills (4)	14.1	18.4	(4.3)	(23%)	14.9	17.7	(2.8)	(16 %)
Versado	20.2	24.1	(3.9)	(16%)	21.1	23.3	(2.2)	(9 %)
Total Permian	128.4	120.7	7.7		123.9	100.7	23.2	
SouthTX (5)	31.4	19.8	11.6	59 %	27.3	13.0	14.3	110%
North Texas	37.0	41.1	(4.1)	(10%)	36.3	40.9	(4.6)	(11 %)
SouthOK (5)	47.3	31.5	15.8	50 %	37.6	21.1	16.5	78 %
WestOK (5)	29.7	30.5	(0.8)	(3 %)	28.3	20.4	7.9	39 %
Total Central	145.4	122.9	22.5		129.5	95.4	34.1	
Badlands	7.0	7.5	(0.5)	(7 %)	7.3	5.8	1.5	26 %
Total Field	280.8	251.1	29.7		260.7	201.9	58.8	
Coastal	40.1	39.4	0.7	2 %	42.2	40.9	1.3	3 %

Total	320.9	290.5	30.4	10 %	302.9	242.8	60.1	25 %
Crude oil gathered, MBbl/d	105.2	106.2	(1.0)	(1 %)	105.2	103.7	1.5	1 %
Natural gas sales, BBtu/d (3)	1,605.8	1,783.6	(177.8)	(10%)	1,646.5	1,435.4	211.1	15 %
NGL sales, MBbl/d	256.1	220.8	35.3	16 %	237.7	185.9	51.8	28 %
Condensate sales, MBbl/d	10.9	11.4	(0.5)	(4 %)	10.2	8.5	1.7	20 %
Average realized prices (7):								
Natural gas, $/MMBtu	1.64	2.37	(0.73)	(31%)	1.70	2.47	(0.77)	(31 %)
NGL, $/gal	0.36	0.38	(0.02)	(5 %)	0.32	0.38	(0.06)	(16 %)
Condensate, $/Bbl	37.94	48.81	(10.87)	(22%)	32.21	46.13	(13.92)	(30 %)

(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, including the volumes related to plants acquired in the APL merger.
(2) Plant natural gas inlet represents our undivided interest in the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes wellhead gathered volumes moved from Sand Hills via pipeline to SAOU for processing.
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Badlands natural gas inlet represents the total wellhead gathered volume.
(7) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

The decrease in gross margin was primarily due to lower commodity prices. Throughput volumes were relatively flat. The plant inlet volume increase in the Permian region was driven by SAOU and WestTX. The volume increase at SouthTX partially offset an overall volume decrease in the Central region. All other Permian and Central region business units experienced reduced producer activity and volumes. NGL production and NGL sales volumes increased and natural gas sales volumes decreased primarily due to increased ethane recovery at SouthOK and increased volumes at SouthTX during the second quarter of 2016. Badlands natural gas volumes increased due to plant and system expansions, while crude oil volumes were relatively flat.

Despite increased expenses associated with the commencement of commercial operations in April 2016 at the Buffalo Plant in WestTX and planned maintenance in Sand Hills and Versado greater than the comparable period, operating expenses decreased primarily due to a continued focus on cost reductions.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

The increase in gross margin was primarily due to the inclusion of the TPL volumes for two quarters of 2016 partially offset by significantly lower commodity prices and lower throughput volumes on our other systems. The plant inlet volume increases in the Permian region attributable to SAOU were offset by reduced producer activity and planned maintenance at Sand Hills and Versado and in the Central region by reduced producer activity and volumes in North Texas. Badlands crude oil and natural gas volumes increased due to plant and system expansions. Coastal plant inlet volumes decreased due to current market conditions and the decline of off-system volumes partially offset by additional higher GPM volumes.

Excluding the impact of adding operating expenses for TPL and system expansions, operating expenses for most areas were significantly lower due to a continued focused cost reduction effort.

Gross Operating Statistics Compared to Actual Reported

The table below provides a reconciliation between gross operating statistics and the actual reported operating statistics for the Gathering and Processing segment:

	Three Months Ended June 30, 2016			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU (4)	259.2	100 %	259.2	259.2
WestTX (5)(6)(7)	677.6	73 %	493.3	493.3
Sand Hills (4)	135.8	100 %	135.8	135.8
Versado (8)	168.8	63 %	106.3	168.8
Total Permian	1,241.4		994.6	1,057.1
SouthTX (5)	265.4	100 %	265.4	265.4
North Texas	327.5	100 %	327.5	327.5
SouthOK (5)	470.7	Varies (9)	393.7	470.7
WestOK (5)	445.6	100 %	445.6	445.6
Total Central	1,509.2		1,432.2	1,509.2
Badlands (10)	51.2	100 %	51.2	51.2
Total Field	2,801.8		2,478.0	2,617.5
Gross NGL production, MBbl/d (2)				
SAOU (4)	32.2	100 %	32.2	32.2
WestTX (5)(6)(7)	85.0	73 %	61.9	61.9
Sand Hills (4)	14.1	100 %	14.1	14.1
Versado (8)	20.2	63 %	12.7	20.2
Total Permian	151.5		120.9	128.4
SouthTX (5)	31.4	100 %	31.4	31.4
North Texas	37.0	100 %	37.0	37.0
SouthOK (5)	47.3	Varies (9)	44.0	47.3
WestOK (5)	29.7	100 %	29.7	29.7
Total Central	145.4		142.1	145.4
Badlands	7.0	100 %	7.0	7.0
Total Field	303.9		270.0	280.8

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these 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.

(4) Includes wellhead gathered volumes moved from Sand Hills to SAOU for processing.
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(7) Includes the Buffalo Plant that commenced commercial operations in April 2016.
(8) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(9) SouthOK includes the Centrahoma joint venture, of which TPL owns 60% and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(10) Badlands natural gas inlet represents the total wellhead gathered volume.

	Three Months Ended June 30, 2015			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU (4)	237.7	100 %	237.7	237.7
WestTX (5)(6)	595.0	73 %	433.2	433.2
Sand Hills (4)	171.5	100 %	171.5	171.5
Versado (7)	185.6	63 %	116.9	185.6
Total Permian	1,189.8		959.3	1,028.0
SouthTX (5)	150.9	100 %	150.9	150.9
North Texas	356.1	100 %	356.1	356.1
SouthOK (5)	487.2	Varies (8)	408.1	487.2
WestOK (5)	597.4	100 %	597.4	597.4
Total Central	1,591.6		1,512.5	1,591.6
Badlands (9)	46.8	100 %	46.8	46.8
Total Field	2,828.2		2,518.6	2,666.4
Gross NGL production, MBbl/d (2)				
SAOU (4)	27.7	100 %	27.7	27.7
WestTX (5)(6)	69.3	73 %	50.5	50.5
Sand Hills (4)	18.4	100 %	18.4	18.4
Versado (7)	24.1	63 %	15.2	24.1
Total Permian	139.5		111.8	120.7
SouthTX (5)	19.8	100 %	19.8	19.8
North Texas	41.1	100 %	41.1	41.1
SouthOK (5)	31.5	Varies (8)	28.1	31.5
WestOK (5)	30.5	100 %	30.5	30.5
Total Central	122.9		119.5	122.9
Badlands	7.5	100 %	7.5	7.5
Total Field	269.9		238.8	251.1

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these 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, other than for the volumes related to the APL merger, for which the denominator is 31 days.
(4) Includes wellhead gathered volumes moved from Sand Hills to SAOU for processing
(5) Operations acquired as part of the APL merger effective February 27, 2015.
(6) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.

(7) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(8) SouthOK includes the Centrahoma joint venture, of which TPL owns 60% and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(9) Badlands natural gas inlet represents the total wellhead gathered volume.

Logistics and Marketing Segment

	Three Months Ended June 30,				Six Months Ended June 30,			
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
	($ in millions)							
Gross margin	$ 197.6	$ 221.8	$ (24.2)	(11%)	$ 407.9	$ 468.9	$ (61.0)	(13%)
Operating expenses	55.8	58.1	(2.3)	(4%)	109.4	113.5	(4.1)	(4%)
Operating margin	$ 141.8	$ 163.7	$ (21.9)	(13%)	$ 298.5	$ 355.4	$ (56.9)	(16%)
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	329.8	357.8	(28.0)	(8%)	312.7	349.3	(36.6)	(10%)
LSNG treating volumes (2)	23.1	25.0	(1.9)	(8%)	22.0	22.2	(0.2)	(1%)
Benzene treating volumes (2)	23.1	25.0	(1.9)	(8%)	22.0	22.2	(0.2)	(1%)
Export volumes, MBbl/d (4)	181.3	164.3	17.0	10%	181.2	177.9	3.3	2%
NGL sales, MBbl/d	463.6	387.9	75.7	20%	472.8	428.6	44.2	10%
Average realized prices:								
NGL realized price, $/gal	$ 0.48	$ 0.46	$ 0.02	4%	$ 0.44	$ 0.51	$ (0.07)	(14%)

(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 year.
(2) Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the Logistics and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses.
(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.
(4) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine terminal that are destined for international markets.

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

Logistics and Marketing gross margin decreased due to the realization in 2015 of contract renegotiation fees related to our crude and condensate splitter project, lower LPG export margin, lower fractionation margin and lower terminaling and storage throughput. LPG export margin decreased due to lower fees partially offset by higher volumes. Fractionation gross margin decreased due to lower supply volume, a decrease in system product gains and the variable effects of lower fuel and power which are largely reflected in lower operating expenses (see footnote (2) above).

Operating expenses decreased primarily due to lower fuel and power expense, and lower maintenance expense resulting from continued focused cost reduction efforts. These decreases were partially offset by higher taxes and labor associated with the start-up of CBF Train 5.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

The six month results were impacted by the same factors as discussed above for the quarter. An additional offsetting driver was increased marketing gains in 2016.

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	2016 vs. 2015	2016	2015	2016 vs. 2015
	($ in millions)					
Gross margin	$ 18.6	$ 17.1	$ 1.5	$ 45.7	$ 38.8	$ 6.9
Operating margin	$ 18.6	$ 17.1	$ 1.5	$ 45.7	$ 38.8	$ 6.9

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash flow hedges. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column. The primary purpose of our commodity risk management activities is to mitigate a portion of the impact of commodity prices on our operating cash flow. We have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes and (ii) NGL and condensate equity volumes in our Gathering and Processing Operations that result from percent of proceeds or liquid processing arrangements by entering into derivative instruments. Because we are essentially forward-selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

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

	Three Months Ended June 30, 2016			Three Months Ended June 30, 2015			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2016 vs. 2015
Natural gas (BBtu)	10.7	$ 1.27	$ 13.6	5.1	$ 1.72	$ 8.7	$ 4.9
NGL (MMgal)	28.1	0.01	0.3	10.6	0.71	7.5	(7.2)
Crude oil (MBbl)	0.3	15.72	4.4	0.2	24.89	5.2	(0.8)
Non-hedge accounting (2)			-			(4.0)	4.0
Ineffectiveness (3)			0.3			(0.3)	0.6
			$ 18.6			$ 17.1	$ 1.5

	Six Months Ended June 30, 2016			Six Months Ended June 30, 2015			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2016 vs. 2015
Natural gas (BBtu)	20.2	$ 1.33	$ 26.8	10.1	$ 1.48	$ 14.9	$ 11.9
NGL (MMgal)	58.9	0.07	4.0	15.0	0.63	9.5	(5.5)
Crude oil (MBbl)	0.5	23.82	11.5	0.4	28.73	10.5	1.0
Non-hedge accounting (2)			3.1			3.2	(0.1)
Ineffectiveness (3)			0.3			0.7	(0.4)
			$ 45.7			$ 38.8	$ 6.9

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.
(3) Ineffectiveness primarily relates to certain crude hedging contracts and certain acquired hedges of APL that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to us and included in the acquisition date fair value of assets acquired. Derivative settlements of $6.3 million and $15.1 million related to these novated contracts were received during the three and six months ended June 30, 2016 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired with no effect on results of operations.

Our Liquidity and Capital Resources

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

Our main sources of liquidity and capital resources are cash distributions received from the Partnership, borrowings under the TRC Revolver and access to capital markets. For companies involved in hydrocarbon production, transportation and other oil and gas related services, the capital markets continue to experience volatility. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. We continually monitor our liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRC Revolver.

Our liquidity as of July 18, 2016 was:

	July 18, 2016 (In millions)
Cash on hand	$ 35.1
Total commitments under the TRC Revolver	670.0
	705.1
Less: Outstanding borrowings under the TRC Revolver	(250.0)
Total liquidity	$ 455.1

Other potential capital resources include:

- Our right to request an additional $200 million in commitment increases under our Revolver, subject to the terms therein. The TRC Revolver matures on February 27, 2020.

A portion of our capital resources may be allocated to letters of credit to satisfy certain counterparty credit requirements. These letters of credit reflect our non-investment grade status, as assigned by Moody's and S&P. They also reflect certain counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors.

The Partnership's Liquidity and Capital Resources

The Partnership's ability to finance its operations, including funding capital expenditures and acquisitions, meeting indebtedness obligations, refinancing its indebtedness and meeting 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 our control. These include weather, commodity prices (particularly for natural gas and NGLs) and ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

The Partnership's main sources of liquidity and capital resources are internally generated cash flow from operations, contributions from us that are funded through our access to debt and equity markets, borrowings under the TRP Revolver, borrowings under the Securitization Facility, 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. We continually monitor the Partnership's liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

The Partnership's liquidity as of July 18, 2016 was:

		July 18, 2016 (In millions)
Cash on hand		$ 149.9
Total commitments under the TRP Revolver		1,600.0
Total availability under the Securitization Facility		225.0
		1,974.9
Less:	Outstanding borrowings under the TRP Revolver	(70.0)
	Outstanding borrowings under the Securitization Facility	(225.0)
	Outstanding letters of credit under the TRP Revolver	(13.3)
	Total liquidity	$ 1,666.6

Other potential capital resources include:

- The Partnership's right to request an additional $300 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on October 3, 2017.

A portion of the Partnership’s capital resources may be allocated to letters of credit to satisfy certain counterparty credit requirements. These letters of credit reflect our non-investment grade status, as assigned to us by Moody’s and S&P. They also reflect certain counterparties’ views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors.

Working Capital

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

Our working capital, exclusive of current debt obligations, decreased $113.6 million from December 31, 2015 to June 30, 2016. The major items contributing to this decrease were a decrease in our net risk management working capital position due to changes in the forward prices of commodities, increased plant settlement accruals, lower inventory balances primarily due to a change in product mix, lower commodity receivables due to lower revenue and lower facility receivables, higher ad valorem tax accruals and preferred stock dividends payable. Partially offsetting these items were decreased capital accruals, an increase in the cash balance, and a decrease in accrued interest primarily due to debt repurchases. The increase of $5.7 million in current debt obligations was due to higher receivables available for the TRP AR Securitization Facility.

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

Cash Flow

Cash Flows from Operating Activities

Our Consolidated Statements of Cash Flows included in our historical consolidated financial statements employs the traditional indirect method of presenting cash flows from operating activities. Under the indirect method, net cash provided by operating activities is derived by adjusting 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 operating cash flows using the direct method as a supplement to the presentation in our consolidated financial statements:

	Six Months Ended June 30,		
	2016	2015	2016 vs. 2015
	(In millions)		
Cash flows from operating activities:			
Cash received from customers	$2,978.5	$3,501.0	$(522.5)
Cash received from (paid to) derivative counterparties	51.1	60.9	(9.8)
Cash outlays for:			
Product purchases	2,096.8	2,568.2	(471.4)
Operating expenses	256.9	262.4	(5.5)
General and administrative expenses	75.3	115.1	(39.8)
Cash distributions from equity investments (1)	—	(6.9)	6.9
Interest paid, net of amounts capitalized (2)	142.2	101.3	40.9
Income taxes paid, net of refunds	1.1	13.2	(12.1)
Other cash (receipts) payments	(0.2)	24.4	(24.6)
Net cash provided by operating activities	$457.5	$484.2	$(26.7)

(1) Excludes $3.9 million and $0.1 million included in investing activities for the six months ended June 30, 2016 and 2015 related to distributions from GCF and the T2 Joint Ventures that exceeded cumulative equity earnings.

(2)

Net of capitalized interest paid of $6.3 million and $5.5 million included in investing activities for the six months ended June 30, 2016 and 2015.

Lower commodity prices were the primary contributor to decreased cash collections and payments for product purchases in 2016 compared to 2015. Interest payments were higher in 2016, primarily due to the timing of the interest payments related to the new borrowings in 2015. Cash payments for compensation related costs were lower in 2016, primarily due to lower bonus payout and lower insurance premium payments. Other cash payments in 2016 were lower, mainly due to the transaction costs of the Atlas mergers in 2015.

Cash Flows from Investing Activities

Six Months Ended June 30,		
2016	2015	2016 vs. 2015
(In millions)		
$(305.2)	$(2,011.8)	$1,706.6

The decrease in net cash used in investing activities for the six months ended June 30, 2016 compared to the six months ended June 30, 2015 was primarily due to the $1,574.4 million outlay for the cash portion of the Atlas mergers in 2015. Growth and maintenance capital expenditures decreased $93.1 million for the six months ended June 30, 2016 as compared with the six months ended June 30, 2015.

Cash Flows from Financing Activities

Six Months Ended June 30, 2016	2015	2016 vs. 2015
(In millions)		
$(121.6)	$1,552.3	$(1,673.9)

Net cash provided by (used in) financing activities decreased in the six months ended June 30, 2016 as compared with the six months ended June 30, 2015. During the six months ended June 30, 2016, we reduced our debt exposure by repurchasing $534.3 million of the Partnership's senior notes in the open market along with other net debt repayments of $384.3 million; whereas we incurred net borrowings of $1,261.1 million during the six months ended June 30, 2015 primarily associated with the Atlas mergers. Dividends paid to common and preferred shareholders increased $122.7 million while distributions paid to unitholders decreased $76.8 million for the six months ended June 30, 2016 as compared with the six months ended June 30, 2015.

Proceeds from the issuance of common and preferred stock increased $836.6 million for the six months ended June 30, 2016, as compared with the six months ended June 30, 2015, primarily due to the Series A Preferred offering in March 2016. As a result of the TRC/TRP merger that resulted in its common units no longer being publicly traded, the Partnership had no public offerings of common units in the six months ended June 30, 2016. In comparison, the Partnership received $295.8 million of proceeds from the sale of common units in the six months ended June 30, 2015.

Distributions from the Partnership and Dividends of TRC

Distributions

In accordance with the Partnership Agreement, the Partnership must distribute all of its available cash, as defined in the Partnership Agreement, and as determined by the general partner, to preferred unitholders monthly and to common unitholders of record within 45 days after the end of each quarter. As a result of the TRC/TRP Merger, we are entitled to receive all available Partnership distributions after payment of preferred distributions each quarter. The following details the distributions declared and paid by the Partnership, net of the IDR Giveback, during 2016:

- On February 9, 2016, total distributions of $200.4 million were declared and paid for the three months ended December 31, 2015, of which $61.4 million was paid to us.
- On May 12, 2016, distributions declared for the three months ended March 31, 2016, of $154.8 million were paid to us.

- On July 20, 2016, distributions of $178.9 million were declared for the three months ended June 30, 2016, which will be paid to us on August 11, 2016.

Distributions on the Partnership's outstanding Series A Preferred Units are declared and paid monthly. For the six months ended June 30, 2016, $5.6 million of preferred distributions were paid. The Partnership has accrued distributions to Series A Preferred Unitholders of $0.9 million for June 30, 2016, which were paid subsequently on July 15, 2016. On July 18, 2016, the board of directors declared a monthly cash distribution of $0.1875 per preferred unit for July 2016. This distribution will be paid on August 15, 2016.

Dividends

The following table details the dividends declared and/or paid by us for the six months ended June 30, 2016:

Three Months Ended	Date Paid or To Be Paid	Total Dividends Declared	Amount of Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
(In millions, except per share amounts)					
June 30, 2016	August 15, 2016	$ 153.1	$ 151.6	$ 1.5	$ 0.91000
March 31, 2016	May 16, 2016	147.8	146.1	1.7	0.91000
December 31, 2015	February 9, 2016	51.7	51.0	0.7	0.91000

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

As of June 30, 2016, cash dividends accrued for our Series A preferred stock were $22.9 million, which will be paid on August 12, 2016. Cash dividends paid were $3.8 million for the six months ended June 30, 2016.

Capital Requirements

Our capital requirements relate to capital expenditures, which are classified as expansion expenditures, which include business acquisitions, or maintenance expenditures. 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.

	Six Months Ended June 30,	
	2016	2015
	(In millions)	
Capital expenditures:		
Consideration for business acquisitions	$—	$5,024.2
Non-cash value of acquisition (1)	—	(3,449.8)
Business acquisitions, net of cash acquired	—	1,574.4
Expansion	256.6	338.3
Maintenance	35.2	46.6
Gross capital expenditures	291.8	384.9
Transfers from materials and supplies inventory to property, plant and equipment	(0.9)	(1.6)
Decrease in capital project payables and accruals	16.8	52.9
Cash outlays for capital projects	307.7	436.2
Total	$307.7	$2,010.6

(1) Includes the non-cash value of consideration and the Special GP Interest (see Note 4 – Business Acquisitions of the "Consolidated Financial Statements").

We currently estimate that we will invest approximately $525 million in net growth capital expenditures for announced projects in 2016. Given our objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, we anticipate that over time that we will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. Our expansion capital expenditures decreased for the six months ended June 30, 2016 as compared with the six months ended June 30, 2015, primarily due to reduced Badlands spending activity and CBF Train 5 construction costs in 2016. Although CBF Train 5 started up in the second quarter of 2016, only slightly more than 20% of the construction costs were incurred in 2016. Our maintenance capital expenditures decreased for the six months ended June 30, 2016 as compared with the six months ended June 30, 2015, primarily due to fewer well connects and lengthened maintenance cycle times resulting from decreases in producer activity, as well as a higher percentage of environmental repairs incurred in the first six months of 2015 versus 2016.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are set forth in Part II, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report and our Current Report on Form 8-K filed with the SEC on May 23, 2016. There were no significant updates or revisions to these policies during the six months ended June 30, 2016.

Off-Balance Sheet Arrangements

As of June 30, 2016, there were $33.9 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety, and (iii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Contractual Obligations

As of June 30, 2016, there have been no significant changes in the contractual obligations as presented in our Annual Report and our Current Report on Form 8-K filed with the SEC on May 23, 2016, except as noted for debt repurchases which are disclosed in Note 9 – Debt Obligations in our Consolidated Financial Statements included in this Quarterly Report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Commodity Price Risk

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by our customers. We do not use risk sensitive instruments for trading purposes.

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

The primary purpose of the commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce fluctuations in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of June 30, 2016, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in our Gathering and Processing operations and (ii) NGL and condensate equity volumes in our Gathering and Processing operations that result from our percent-of-proceeds processing arrangements by entering into derivative instruments. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, for which we hedge incrementally lower percentages of expected equity volumes. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

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

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

For all periods presented, we have entered into hedging arrangements for a portion of our forecasted equity volumes. During the three months ended June 30, 2016 and 2015, our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $18.6 million and $17.1 million. During the six months ended June 30, 2016 and 2015, our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $45.7 million and $38.8 million.

As of June 30, 2016, we had the following derivative instruments designated as hedging instruments that will settle during the years ending below:

Natural GAS

Instrument		Price		MMBtu/d				
Type	Index	$/MMBtu		2016	2017	2018	2019	Fair Value (In millions)
Swap	IF-NGPL MC	3.93		3,456	-	-	-	$ 0.7
Swap	IF-Waha	2.96		77,736	-	-	-	1.1
Swap	IF-Waha	2.74		-	41,300	-	-	(5.0)
Swap	IF-Waha	2.61		-	-	36,300	-	(4.7)
Swap	IF-Waha	2.84		-	-	-	8,083	(0.4)
				77,736	41,300	36,300	8,083	
		Put Price	Call Price					
Collar	IF-Waha	2.85	3.47	7,500	-	-	-	0.2
Collar	IF-Waha	3.00	3.67	-	7,500	-	-	0.4
Collar	IF-Waha	3.25	4.20	-	-	1,849	-	0.1
				7,500	7,500	1,849	-	
Swap	IF-PB	3.12		18,508	-	-	-	0.8
Swap	IF-PB	2.51		-	10,900	-	-	(2.1)
Swap	IF-PB	2.51		-	-	10,900	-	(1.6)
				18,508	10,900	10,900	-	
		Put Price	Call Price					
Collar	IF-PB	2.65	3.31	15,400	-	-	-	0.0
Collar	IF-PB	2.80	3.50	-	15,400	-	-	0.1
Collar	IF-PB	3.00	3.65	-	-	7,637	-	0.5
				15,400	15,400	7,637	-	
Swap	NG-NYMEX	4.13		30,887	-	-	-	6.2
Swap	NG-NYMEX	4.11		-	18,082	-	-	5.6
				30,887	18,082	-	-	

Basis Swap	EP_PERMIAN	(0.1703)	15,489	-	-	-	(0.1)
Basis Swap	EP_PERMIAN	(0.1444)	-	9,041	-	-	(0.1)
			15,489	9,041	-	-	
Basis Swap	PEPL	(0.3278)	15,489	-	-	-	(0.4)
Basis Swap	PEPL	(0.3308)	-	9,041	-	-	(0.5)
			15,489	9,041	-	-	
Basis Swap	TENN_800	(0.0550)	10,027	-	-	-	(0.0)
Basis Swap	NGPL_TXOK	0.0967	20,054	-	-	-	(0.0)
Basis Swap	WAHA	0.1283	(20,054)	-	-	-	(0.1)
Total			194,492	111,264	56,686	8,083	
							$ 0.7

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NGLs

Instrument		Price		Bbl/d				
Type	Index	$/gal		2016	2017	2018	2019	Fair Value (In millions)
Swap	C2-OPIS-MB	0.2209		870	-	-	-	(0.2)
Swap	C2-OPIS-MB	0.2294		-	870	-	-	(0.9)
Swap	C2-OPIS-MB	0.2371		-	-	658	-	(0.8)
Total				870	870	658	-	
		Put Price						
Option	C2-OPIS-MB	0.269		-	548	-	-	0.2
Option	C2-OPIS-MB	0.296		-	-	1,644	-	0.8
Total				-	548	1,644	-	
Future	C2-OPIS-MB	0.1963		3,152	-	-	-	(1.8)
Future	C2-OPIS-MB	0.2523		-	2,110	-	-	(1.3)
Total				3,152	2,110	-	-	
Swap	C3-OPIS-MB	1.1153		1,709	-	-	-	7.2
Swap	C3-OPIS-MB	1.0400		-	658	-	-	4.9
Total				1,709	658	-	-	
Future	C3-OPIS-MB	0.1928		1,190	-	-	-	(4.3)
Future	C3-OPIS-MB	0.5442		-	1,036	-	-	(0.5)
Total				1,190	1,036	-	-	
Future	NC4-OPIS-MB	0.5165		408	-	-	-	(0.6)
Swap	C5-OPIS-MB	0.9600		320	-	-	-	(0.1)
Swap	C5-OPIS-MB	0.9600		-	320	-	-	(0.3)
Swap	C5-OPIS-MB	0.9600		-	-	320	-	(0.3)
Swap	C5-OPIS-MB	1.0375		-	-	-	79	0.1
Total				320	320	320	79	
		Put Price	Call Price					
Collar	C2-OPIS-MB	0.200	0.235	410	-	-	-	(0.1)
Collar	C2-OPIS-MB	0.240	0.290	-	410	-	-	(0.2)
Total				410	410	-	-	

		Put Price	Call Price					
Collar	C3-OPIS-MB	0.560	0.68000	380	-	-	-	0.1
Collar	C3-OPIS-MB	0.570	0.68625	-	380	-	-	0.3
Total				380	380	-	-	
		Put Price	Call Price					
Collar	C5-OPIS-MB	1.200	1.390	130	-	-	-	0.2
Collar	C5-OPIS-MB	1.210	1.415	-	130	-	-	0.5
Collar	C5-OPIS-MB	1.230	1.385	-	-	32	-	0.1
Total				130	130	32	-	
Total				8,569	6,462	2,654	79	
								$ 3.0

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CONDENSATE

Instrument Type	Index	Price $/Bbl		Bbl/d 2016	2017	2018	2019	Fair Value (In millions)
Swap	NY-WTI	59.98		2,770	-	-	-	$ 5.1
Swap	NY-WTI	56.15		-	1,850	-	-	2.5
Swap	NY-WTI	47.43		-	-	1,350	-	(3.1)
Swap	NY-WTI	52.00		-	-	-	223	(0.2)
				2,770	1,850	1,350	223	
		Put Price	Call Price					
Collar	NY-WTI	57.08	67.97	790	-	-	-	1.2
Collar	NY-WTI	58.56	69.95	-	790	-	-	2.5
Collar	NY-WTI	60.00	71.60	-	-	101	-	0.4
				790	790	101	-	
Total Sales				3,560	2,640	1,451	223	
								$ 8.4

As of June 30, 2016, we had the following derivative instruments that are not designated as hedges and are marked-to-market:

NATURAL GAS

Instrument Type	Index	Price $/MMBtu	MMBtu/d 2016	2017	2018	2019	Fair Value (In millions)
Basis Swap	Various	(0.0550)	10,027	-	-	-	$ (0.1)

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which they have been hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges (other than with respect to purchased calls). For derivative instruments not designated as cash flow hedges, these contracts are marked-to-market and recorded in revenues.

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. For futures contracts executed through a counterparty that clears the hedges through an exchange, the classification of these instruments is Level 1 within the fair value hierarchy. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 16- Fair Value Measurements of 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 Credit Agreement. The Partnership is exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and the Securitization Facility. As of June 30, 2016, neither we nor the Partnership have any interest rate hedges. However, we or the Partnership 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 Credit Agreement, TRP Revolver and the Partnership’s securitization facility will also increase. As of June 30, 2016, the Partnership had $280.0 million in outstanding variable rate borrowings under the TRP Revolver and its Securitization Facility, and we had outstanding variable rate borrowings of $275.0 million under our revolving credit facility and $160.0 million under our term loan facility. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact the Partnership's annual interest expense by $2.8 million and the TRC Non-Partnership annual interest expense by $4.4 million.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Our futures contracts have limited credit risk since they are cleared through an exchange and are settled daily. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. We have master netting provisions in the International Swap Dealers Association agreements with all of our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $34.6 million as of June 30, 2016. The range of losses attributable to our individual counterparties would be between less than $0.1 million and $15.4 million, depending on the counterparty in default.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have an established policy and various procedures to manage our credit exposure risk, including initial and subsequent credit risk analyses, credit limits and terms and credit enhancements when necessary. We use credit enhancements including (but not limited to) letters of credit, prepayments, parental guarantees and rights of offset to limit credit risk to ensure that our established credit criteria are followed and financial loss is mitigated or minimized.

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable, annual operating income would decrease by $4.9 million in the year of the assessment.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Management, 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 in this Quarterly Report. Based on this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were not effective as a result of a material weakness in our internal control over financial reporting as disclosed in our 2015 Annual Report on Form 10-K. Management has concluded that the material weakness that was present as of December 31, 2015 was also present as of June 30, 2016.

Previously Identified Material Weakness in Internal Control Over Financial Reporting

As previously disclosed in our 2015 Annual Report on Form 10-K, we did not maintain adequate controls over the valuation of certain assets in the Atlas mergers. Specifically, our review procedures over the development and application of inputs, assumptions, and calculations used in cash flow-based fair value measurements associated with business combinations did not operate as designed and at an appropriate level of detail commensurate with our financial reporting requirements.

Remediation Status

We have enhanced our internal control framework applicable to business acquisitions to include formal processes covering the development, application and review of inputs, assumptions, and calculations used in cash flow-based value measurements. Cash flow-based fair value measurements are also typically used for asset and goodwill impairment testing. We have not had any events or conditions since December 31, 2015 that have required the use of cash flow-based fair value measurements. As such, neither we nor our external auditors have had the opportunity to fully test the operating effectiveness of our remediated internal control framework. We will be able to fully test our remediated controls over cash flow-based fair value measurements when we perform our annual goodwill impairment testing for the 2016 reporting cycle, or earlier if another need arises for such value measurements.

Changes in Internal Control Over Financial Reporting During the Quarter Ended June 30, 2016

During the three months ended June 30, 2016, there have not been any changes in our internal control over financial reporting that have materially affected, or are 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 17 – Contingencies, under the heading “Legal Proceedings” included in the Notes to Consolidated Financial Statements included under Part I, Item 1 of this Quarterly Report, which is incorporated by reference into this item.

Item 1A. Risk Factors.

For an in-depth discussion of our risk factors, see “Part I—Item 1A Risk Factors” of our 2015 Annual Report, except for the additional risk factors discussed below. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

The Preferred Shares give the holders thereof liquidation and distribution preferences, certain rights relating to our business and management, and the ability to convert such shares into our common stock, potentially causing dilution to our common stockholders.

In March 2016, we issued 965,100 shares of Series A Preferred Stock, which rank senior to the common stock with respect to distribution rights and rights upon liquidation. Subject to certain exceptions, so long as any Preferred Shares remains outstanding, we may not declare any dividend or distribution on our common stock unless all accumulated and unpaid dividends have been declared and paid on the Preferred Shares. In the event of our liquidation, winding-up or dissolution, the holders of the Preferred Shares would have the right to receive proceeds from any such transaction before the holders of the common stock. The payment of the liquidation preference could result in common stockholders not receiving any consideration if we were to liquidate, dissolve or wind up, either voluntarily or involuntarily. Additionally, the existence of the liquidation preference may reduce the value of the common stock, make it harder for us to sell shares of common stock in offerings in the future, or prevent or delay a change of control.

In connection with the issuance of the Preferred Shares, we entered into an agreement with Stonepeak pursuant to which we granted them the right to appoint an observer to our Board of Directors, such observer having the right to become a member of our Board of Directors under certain circumstances. In addition, the Certificate of Designations governing the Preferred Shares provides the holders of the Preferred Shares with the right to vote, under certain conditions, on an as-converted basis with our common stockholders on matters submitted to a stockholder vote. Also, so long as any Preferred Shares are outstanding, subject to certain exceptions, the affirmative vote or consent of the holders of at least a majority of the outstanding Preferred Shares, voting together as a separate class, will be necessary for effecting or validating, among other things: (i) any issuance of stock senior to the Preferred Shares, (ii) any issuance or increase by any of the our consolidated subsidiaries of any issued or authorized amount of, any specific class or series of securities, (iii) any issuance by us of parity stock, subject to certain exceptions and (iv) any incurrence of indebtedness by us and our consolidated subsidiaries for borrowed monies, other than under our existing credit agreement and the Partnership’s existing credit agreement (or replacement commercial bank credit facilities) in an aggregate amount up to $2.75 billion, or indebtedness that complies with a specified fixed charge coverage ratio. These restrictions may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Furthermore, the conversion of the Preferred Shares into common stock twelve years after the issuance of the Preferred Shares, pursuant to the terms of the Certificate of Designations, may cause substantial dilution to holders of the common stock. Because our Board of Directors is entitled to designate the powers and preferences of preferred stock without a vote of our shareholders, subject to NYSE rules and regulations, our shareholders will have no control over what designations and preferences our future preferred stock, if any, will have.

The issuance of common stock upon exercise of the Series A Warrants and Series B Warrants may cause dilution to existing common stockholders and may place downward pressure on the trading price of our common stock.

In connection with our issuance of Preferred Shares in March 2016, we issued (i) Series A Warrants exercisable into a maximum of 13,550,004 shares of common stock, with an exercise price of $18.88 per share and (ii) Series B Warrants exercisable into a maximum of 6,533,727 shares of common stock, with an exercise price of $25.11 per share. Both the Series A Warrants and Series B Warrants are exercisable beginning September 16, 2016 and expire March 16, 2023. The future exercise of the Series A Warrants and Series B Warrants by the holders of those securities may cause a reduction in the relative voting power and percentage ownership interests of our other common stockholders, and may place downward pressure on the trading price of our common stock.

Changes in future business conditions could cause recorded goodwill and property, plant and equipment assets to become further impaired, and our financial condition and results of operations could suffer if there is an additional impairment of goodwill or other intangible assets with indefinite lives, intangible assets with definite lives, or property, plant and equipment assets.

During 2015, global oil and natural gas commodity prices, particularly crude oil, significantly decreased as compared to 2014, and global oil and natural gas commodity prices remained depressed in the second quarter of 2016. This decrease in commodity prices has had, and is expected to continue to have, a negative impact on the demand for our services and our market capitalization. Should energy industry conditions further deteriorate, there is a possibility that goodwill, intangible assets and property, plant and equipment may be impaired in a future period. Any additional impairment charges that we may take in the future could be material to our financial results. We cannot accurately predict the amount and timing of any impairment of goodwill, intangible assets or property, plant and equipment. For a further discussion of our impairments, see Note 4 – Business Acquisitions of the Consolidated Financial Statements included in this Quarterly Report.

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

Recent Sales of Unregistered Securities.

Not applicable.

Repurchase of Equity by Targa Resources Corp. or Affiliated Purchasers.

Period	Total number of shares withheld (1)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet to be purchased under the plan
May 1, 2016 - May 31, 2016	957	$ 39.67	—	—
June 1, 2016 - June 30, 2016	36,018	41.83	—	—

(1) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers, directors and key employees that arose upon the lapse of restrictions on restricted stock.

Item 3. Defaults Upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Exhibit 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	Certificate of Designations of Series A Preferred Stock of Targa Resources Corp., filed with the Secretary of State of the State of Delaware on March 16, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
3.3	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.2 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.4	First Amendment to the 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 January 15, 2016 (File No. 001-34991)).
3.5	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)).
3.6	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)).
3.7	Second 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 October 15, 2015 (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)).
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 the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	Targa Resources Corp. (Registrant)	
Date: August 3, 2016	By:	/s/ Matthew J. Meloy Matthew J. Meloy Executive Vice President and Chief Financial Officer (Principal Financial Officer)