Targa Resources Corp.
Form 10-Q
August 03, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017

Or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission File Number: 001-34991

TARGA RESOURCES CORP.

(Exact name of registrant as specified in its charter)

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

(713) 584-1000

(Registrant’s telephone number, including area code)

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

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

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

As of July 31, 2017, there were 215,605,062 shares of the registrant’s common stock, $0.001 par value, outstanding.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, including Targa Resources Partners LP ("the Partnership" or "TRP"), "we," "us," "our," "Targa," "TRC," or the "Company") reports, filings and other public announcements may from tim time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, by the use of forward-looking statements, such as "may," "could," "project," "believe," "anticipate," "expect," "estin "potential," "plan," "forecast" and other similar words.

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the following risks and uncertainties:

- the timing and extent of changes in natural gas, natural gas liquids, 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 natural gas liquid 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, 2016 ("Annual Report") and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Quarterly Report on Form 10-Q for the quarter ended June 30, 2017 ("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 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)
BBtu	Billion British thermal units
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
/d	Per day
GAAP	Accounting principles generally accepted in the United States of America
gal	U.S. gallons
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LACT	Lease Automatic Custody Transfer
LIBOR	London Interbank Offered Rate
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMgal	Million U.S. gallons
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange

Price Index Definitions

C2-OPIS-MB	Ethane, Oil Price Information Service, Mont Belvieu, Texas
C3-OPIS-MB	Propane, Oil Price Information Service, Mont Belvieu, Texas
C5-OPIS-MB	Natural Gasoline, Oil Price Information Service, Mont Belvieu, Texas
EP-PERMIAN	Inside FERC Gas Market Report, El Paso (Permian Basin)
IC4-OPIS-MB	Iso-Butane, Oil Price Information Service, Mont Belvieu, Texas
IF-PB	Inside FERC Gas Market Report, Permian Basin
IF-PEPL	Inside FERC Gas Market Report, Oklahoma Panhandle, Texas-Oklahoma Midpoint
IF-WAHA	Inside FERC Gas Market Report, West Texas WAHA
NC4-OPIS-MB	Normal Butane, Oil Price Information Service, Mont Belvieu, Texas
NG-NYMEX	NYMEX, Natural Gas
WTI-NYMEX	NYMEX, West Texas Intermediate Crude Oil

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.

CONSOLIDATED BALANCE SHEETS

	June 30, 2017 (Unaudited)	December 31, 2016
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$98.7	$73.5
Trade receivables, net of allowances of $0.2 and $0.9 million at June 30, 2017 and December 31, 2016	550.4	674.6
Inventories	197.7	137.7
Assets from risk management activities	35.7	16.8
Income tax receivable	2.0	67.8
Other current assets	30.4	36.4
Total current assets	914.9	1,006.8
Property, plant and equipment	13,313.6	12,518.7
Accumulated depreciation	(3,086.8)	(2,827.7)
Property, plant and equipment, net	10,226.8	9,691.0
Intangible assets, net	2,264.7	1,654.0
Goodwill, net	256.6	210.0
Long-term assets from risk management activities	17.3	5.1
Investments in unconsolidated affiliates	218.4	240.8
Other long-term assets	19.7	63.5
Total assets	$13,918.4	$12,871.2
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$886.0	$843.5
Liabilities from risk management activities	9.5	49.1
Current debt obligations	500.1	275.0
Total current liabilities	1,395.6	1,167.6
Long-term debt	3,937.5	4,606.0
Long-term liabilities from risk management activities	5.5	26.1
Deferred income taxes, net	852.9	941.2
Other long-term liabilities	588.4	215.1
Contingencies (see Note 18)		
Series A Preferred 9.5% Stock, $1,000 per share liquidation preference, (1,200,000 shares authorized, issued and outstanding 965,100 shares), net of discount (see Note 12)	203.3	190.8

Owners' equity:				
Targa Resources Corp. stockholders' equity:				
Common stock ($0.001 par value, 300,000,000 shares authorized)			0.2	0.2
	Issued	Outstanding		
June 30, 2017	216,134,254	215,575,687		
December 31, 2016	185,234,405	184,720,525		
Preferred stock ($0.001 par value, after designation of Series A Preferred Stock: 98,800,000 shares authorized, no shares issued and outstanding)			—	—
Additional paid-in capital			6,666.4	5,506.2
Retained earnings (deficit)			(192.9)	(187.3)
Accumulated other comprehensive income (loss)			21.5	(38.3)
Treasury stock, at cost (558,567 shares as of June 30, 2017 and 513,880 as of December 31, 2016)			(34.3)	(32.2)
Total Targa Resources Corp. stockholders' equity			6,460.9	5,248.6
Noncontrolling interests in subsidiaries			474.3	475.8
Total owners' equity			6,935.2	5,724.4
Total liabilities, Series A Preferred Stock and owners' equity			$13,918.4	$12,871.2

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(Unaudited)			
	(In millions, except per share amounts)			
Revenues				
Sales of commodities	$1,623.8	$1,312.9	$3,481.7	$2,484.0
Fees from midstream services	243.9	270.7	498.6	542.0
Total revenues	1,867.7	1,583.6	3,980.3	3,026.0
Costs and expenses:				
Product purchases	1,420.6	1,145.2	3,074.8	2,156.2
Operating expenses	155.2	138.9	307.2	271.0
Depreciation and amortization expense	203.4	186.1	394.6	379.6
General and administrative expense	51.0	47.0	99.6	92.2
Goodwill impairment	—	—	—	24.0
Other operating (income) expense	0.3	0.1	16.5	1.1
Income from operations	37.2	66.3	87.6	101.9
Other income (expense):				
Interest expense, net	(62.1)	(71.4)	(125.1)	(124.3)
Equity earnings (loss)	(4.2)	(4.4)	(16.8)	(9.2)
Gain (loss) from financing activities	(10.7)	(3.3)	(16.5)	21.4
Other, net	4.4	(0.1)	(4.0)	(0.2)
Income (loss) before income taxes	(35.4)	(12.9)	(74.8)	(10.4)
Income tax (expense) benefit	106.0	(1.7)	34.9	(4.8)
Net income (loss)	70.6	(14.6)	(39.9)	(15.2)
Less: Net income attributable to noncontrolling interests	13.0	8.6	21.8	10.7
Net income (loss) attributable to Targa Resources Corp.	57.6	(23.2)	(61.7)	(25.9)
Dividends on Series A preferred stock	22.9	22.9	45.8	26.7
Deemed dividends on Series A preferred stock	6.3	6.5	12.5	6.5
Net income (loss) attributable to common shareholders	$28.4	$(52.6)	$(120.0)	$(59.1)
Net income (loss) per common share - basic	$0.14	$(0.33)	$(0.61)	$(0.44)
Net income (loss) per common share - diluted	$0.14	$(0.33)	$(0.61)	$(0.44)
Weighted average shares outstanding - basic	203.7	161.6	197.8	134.1
Weighted average shares outstanding - diluted	205.0	161.6	197.8	134.1
Dividends per common share declared for the period	$0.91	$0.91	$1.82	$1.82

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30, 2017			2016		
	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.			$ 57.6			$ (23.2)
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$ 29.8	$ (11.3)	18.5	$ (60.2)	$ 22.9	(37.3)
Settlements reclassified to revenues	(5.7)	2.2	(3.5)	(18.3)	6.9	(11.4)
Other comprehensive income (loss) attributable to Targa Resources Corp.	24.1	(9.1)	15.0	(78.5)	29.8	(48.7)
Comprehensive income (loss) attributable to Targa Resources Corp.			$ 72.6			$ (71.9)
Net income (loss) attributable to noncontrolling interests			$ 13.0			$ 8.6
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	—	—	—	—	—	—
Settlements reclassified to revenues	—	—	—	—	—	—
Other comprehensive income (loss) attributable to noncontrolling interests	—	—	—	—	—	—
Comprehensive income (loss) attributable to noncontrolling interests			$ 13.0			$ 8.6
Total						
Net income (loss)			$ 70.6			$ (14.6)
Other comprehensive income (loss)						
Commodity hedging contracts:						
Change in fair value	29.8	(11.3)	18.5	(60.2)	22.9	(37.3)
Settlements reclassified to revenues	(5.7)	2.2	(3.5)	(18.3)	6.9	(11.4)
Other comprehensive income (loss)	$ 24.1	$ (9.1)	15.0	$ (78.5)	$ 29.8	(48.7)
Total comprehensive income (loss)			$ 85.6			$ (63.3)

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Six Months Ended June 30,					
	2017			2016		
	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.			$ (61.7)			$ (25.9)
Other comprehensive income (loss) attributable to Targa Resources Corp.						
Commodity hedging contracts:						
Change in fair value	$ 96.0	$ (36.5)	59.5	$ (77.1)	$ 29.4	(47.7)
Settlements reclassified to revenues	0.4	(0.1)	0.3	(31.3)	11.9	(19.4)
Other comprehensive income (loss) attributable to Targa Resources Corp.	96.4	(36.6)	59.8	(108.4)	41.3	(67.1)
Comprehensive income (loss) attributable to Targa Resources Corp.			$ (1.9)			$ (93.0)
Net income (loss) attributable to noncontrolling interests			$ 21.8			$ 10.7
Other comprehensive income (loss) attributable to noncontrolling interests						
Commodity hedging contracts:						
Change in fair value	—	—	—	23.6	—	23.6
Settlements reclassified to revenues	—	—	—	(11.1)	—	(11.1)
Other comprehensive income (loss) attributable to noncontrolling interests	—	—	—	12.5	—	12.5
Comprehensive income (loss) attributable to noncontrolling interests			$ 21.8			$ 23.2
Total						
Net income (loss)			$ (39.9)			$ (15.2)
Other comprehensive income (loss)						
Commodity hedging contracts:						
Change in fair value	96.0	(36.5)	59.5	(53.5)	29.4	(24.1)
Settlements reclassified to revenues	0.4	(0.1)	0.3	(42.4)	11.9	(30.5)
Other comprehensive income (loss)	$ 96.4	$ (36.6)	59.8	$ (95.9)	$ 41.3	(54.6)
Total comprehensive income (loss)			$ 19.9			$ (69.8)

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, 2016	184,721	$ 0.2	$ 5,506.2	$ (187.3)	$ (38.3)	514	$ (32.2)	$ 475.8	$ 5,724.4	$ 190.8
Impact of accounting standard adoption (see Note 3)	—	—	—	56.1	—	—	—	—	56.1	—
Compensation on equity grants	—	—	21.5	—	—	—	—	—	21.5	—
Distribution equivalent rights	—	—	(4.6)	—	—	—	—	—	(4.6)	—
Shares issued under compensation program	179	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(45)	—	—	—	—	45	(2.1)	—	(2.1)	—
Issuance of common stock	30,721	—	1,558.5	—	—	—	—	—	1,558.5	—
Series A Preferred Stock dividends										
Dividends	—	—	—	(45.8)	—	—	—	—	(45.8)	—
Dividends in excess of retained earnings	—	—	(45.8)	45.8	—	—	—	—	—	—
Deemed dividends - accretion of	—	—	(12.5)	—	—	—	—	—	(12.5)	12.5

beneficial conversion feature										
Common stock dividends										
Dividends	—	—	—	(356.9)	—	—	—	—	(356.9)	—
Dividends in excess of retained earnings	—	—	(356.9)	356.9	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(27.3)	(27.3)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	16.5	16.5	—
Purchase of noncontrolling interests in subsidiary, net of tax impact	—	—	—	—	—	—	—	(12.5)	(12.5)	—
Other comprehensive income (loss)	—	—	—	—	59.8	—	—	—	59.8	—
Net income (loss)	—	—	—	(61.7)	—	—	—	21.8	(39.9)	—
Balance, June 30, 2017	215,576	$ 0.2	$ 6,666.4	$ (192.9)	$ 21.5	559	$ (34.3)	$ 474.3	$ 6,935.2	$ 203.3

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										
Dividends	—	—	—	(26.7)	—	—	—	—	(26.7)	—
Dividends in excess of	—	—	(22.9)	22.9	—	—	—	—	—	—

retained earnings										
Deemed dividends - accretion of beneficial conversion feature	—	—	(6.5)	—	—	—	—	—	(6.5)	—
Common stock dividends										
Dividends	—	—	—	(197.3)	—	—	—	—	(197.3)	—
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 and deferred income taxes	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

See notes to consolidated financial statements

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2017	2016
	(Unaudited)	
	(In millions)	
Cash flows from operating activities		
Net income (loss)	$(39.9)	$(15.2)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	5.9	8.2
Compensation on equity grants	21.5	15.2
Depreciation and amortization expense	394.6	379.6
Goodwill impairment	—	24.0
Accretion of asset retirement obligations	2.2	2.3
Increase (decrease) in redemption value of mandatorily redeemable preferred interests	6.9	(14.6)
Deferred income tax expense (benefit)	(34.5)	4.8
Equity (earnings) loss of unconsolidated affiliates	16.8	9.2
Distributions of earnings received from unconsolidated affiliates	4.0	—
Risk management activities	10.0	3.2
(Gain) loss on sale or disposition of assets	16.2	0.9
(Gain) loss from financing activities	16.5	(21.4)
Change in contingent considerations included in Other expense	1.2	—
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	299.0	19.6
Inventories	(68.6)	12.4
Accounts payable and other liabilities	(187.3)	29.3
Net cash provided by operating activities	464.5	457.5
Cash flows from investing activities		
Outlays for property, plant and equipment	(527.6)	(307.7)
Outlays for business acquisition, net of cash acquired	(570.8)	—
Investments in unconsolidated affiliates	(0.6)	—
Return of capital from unconsolidated affiliates	3.2	3.9
Other, net	(12.8)	(1.4)
Net cash used in investing activities	(1,108.6)	(305.2)
Cash flows from financing activities		
Debt obligations:		
Proceeds from borrowings under credit facilities	1,926.0	1,067.0
Repayments of credit facilities	(1,916.0)	(1,457.0)
Proceeds from borrowings under accounts receivable securitization facility	218.5	121.4
Repayments of accounts receivable securitization facility	(243.5)	(115.7)
Open market purchases of senior notes	—	(534.3)
Redemption of senior notes and term loan	(447.6)	—
Proceeds from issuance of common stock	1,573.4	181.2
Proceeds from issuance of preferred stock and warrants	—	994.1

Costs incurred in connection with financing arrangements	(14.9)	(44.3)
Repurchase of shares and units under compensation plans	(0.6)	(0.4)
Purchase of noncontrolling interests in subsidiary	(12.5)	—
Contributions from noncontrolling interests	16.5	19.1
Distributions to noncontrolling interests	(21.4)	(6.3)
Distributions to Partnership unitholders	(5.6)	(144.7)
Dividends paid to common and preferred shareholders	(403.0)	(201.4)
Payments of distribution equivalent rights	—	(0.3)
Net cash provided by (used in) financing activities	669.3	(121.6)
Net change in cash and cash equivalents	25.2	30.7
Cash and cash equivalents, beginning of period	73.5	140.2
Cash and cash equivalents, end of period	$98.7	$170.9

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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.

See Note 21 – Segment Information for certain financial information regarding 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.

The unaudited consolidated financial statements for the three and six months ended June 30, 2017 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, 2017 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.

On February 17, 2016, we completed the transactions contemplated by the Agreement and Plan of Merger (the “TRC/TRP Merger Agreement”, and such transactions, the “TRC/TRP Merger” or “Buy-in Transaction”), 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, 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. The Preferred Units are reported as noncontrolling interests in our financial statements.

As we continued to control the Partnership after the TRC/TRP Merger, the resulting change in our ownership interest 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 was a taxable exchange that resulted in a book/tax difference in the basis of the underlying assets acquired (our investment in TRP). The tax impact is presented as a reduction of additional paid-in capital consistent with the accounting for tax effects of transactions with noncontrolling interests.

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.

On October 19, 2016, TRP executed the Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (the "Third A&R Partnership Agreement"), effective as of December 1, 2016. The Third A&R Partnership Agreement (i) eliminated the IDRs held by the General Partner, and related distribution and allocation provisions, (ii) eliminated the Special GP Interest held by the General Partner, (iii) provided the ability to declare monthly distributions in addition to quarterly distributions, (iv) modified certain provisions relating to distributions from available cash, (v) eliminated the Class B Unit provisions and (vi) made changes to reflect the passage of time and removed provisions that were no longer applicable. In connection with the Third A&R Partnership Agreement, on December 1, 2016, TRP issued to the General Partner (i) 20,380,286 Common Units and 424,590 General Partner Units in exchange for the elimination of the IDRs and (ii) 11,267,485 Common Units and 234,739 General Partner Units in exchange for the elimination of the Special GP Interest.

We have historically calculated the provision for income taxes during interim reporting periods by applying an estimate of the annual effective tax rate for the full fiscal year to ordinary income or loss (pretax income or loss excluding unusual or infrequently occurring discrete items) for the reporting period. When calculating the annual estimated effective income tax rate for the six months ended June 30, 2017, we were subject to a loss limitation rule because the year-to-date ordinary loss exceeded the full-year expected ordinary loss. The tax benefit for that year-to-date ordinary loss was limited to the amount that would be recognized if the year-to-date ordinary loss were the anticipated ordinary loss for the full year. This requires us to use our statutory rate of 37.3% rather than the annual estimated effective tax rate to calculate the benefit for the period. The income tax benefit for the three months ended June 30, 2017 is the result of the difference between the annual effective tax rate used to calculate income tax (expense) benefit for the three months ended March 31, 2017 and the statutory rate used to calculate income tax (expense) benefit for the six months ended June 30, 2017.

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. There were no significant updates or revisions to our policies during the six months ended June 30, 2017, 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 (1) identifying the contracts with customers, (2) identifying the performance obligations in the contracts, (3) determining the transaction price, (4) allocating the transaction price to the performance obligations, and (5) 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 retrospectively 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 standard 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.

In December 2016, the FASB issued ASU 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers. The amendments in this update clarify the disclosure requirements for performance obligations, provide optional exemptions from the disclosure requirement for remaining performance obligations for specific situations in which an entity need not estimate variable consideration to recognize revenue and provide clarified guidance regarding impairment testing of capitalized contract costs.

We expect to adopt this new revenue recognition standard on January 1, 2018, presenting a cumulative effect adjustment in the period the standard is adopted. We also anticipate electing the practical expedient to apply the guidance retrospectively to only those contracts that are not completed contracts at the date of initial application. We have disaggregated contracts within our two segments and are in the process of reviewing contracts and transaction types with counterparties in order to evaluate how the new standard would impact our current revenue recognition and disclosure policies upon adoption. In addition, we are also evaluating the implications around principal versus agent considerations, as well as whether certain contracts within our gathering and processing segment create relationships with counterparties akin to suppliers or involve significant sharing of risks that would exclude such contracts from the scope of Topic 606.

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 consolidated financial statements and accounting practices for leases.

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.

Cash Flow Classification

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). These amendments clarify how entities should classify certain cash receipts and cash payments on the statement of cash flows related to the following transactions: (1) debt prepayment or extinguishment costs; (2) settlement of zero-coupon debt instruments or other debt instruments with coupon rates that are insignificant in relation to the effective interest rate of the borrowing; (3) contingent consideration payments made after a business combination; (4) proceeds from the settlement of insurance claims; (5) proceeds from the settlement of corporate-owned life insurance; (6) distributions received from equity method investees; and (7) beneficial interests in securitization transactions. Additionally, the update clarifies how the predominance principle should be applied when cash receipts and cash payments have aspects of more than one class of cash flows. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2017, with early adoption permitted. We are currently evaluating the effect of the amendments on our consolidated financial statements and related disclosures.

Recognition of Intra-Entity Transfers of Assets Other than Inventory

In October 2016, the FASB issued ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other than Inventory. The amendments in this update are intended to improve the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. Current GAAP prohibits the recognition of current and deferred income taxes for an intra-entity asset transfer until the asset has been sold to an outside party or otherwise recovered, which is an exception to the principle of comprehensive recognition of current and deferred income taxes in GAAP. This update eliminates the exception by requiring entities to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs.

We early adopted the applicable amendments in first quarter of 2017 on a modified retrospective basis which resulted in a cumulative effect adjustment on retained earnings as of January 1, 2017 of $56.1 million in order to recognize unamortized tax expense previously deferred of $40.1 million and deferred tax assets previously unrecognized of $96.2 million. We did not have intra-entity transfers of assets other than inventory during the current period.

Business Combinations

In January 2017, the FASB issued ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business. The amendments clarify the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses by providing an initial required screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. If the screen is not met, then the amendments (1) require that to be considered a business, a set must include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create output and (2) remove the evaluation of whether a market participant could replace missing elements. The amendments also provide a framework to assist entities in evaluating whether both an input and a substantive process are present. These amendments are effective for annual periods beginning after December 15, 2017, including interim periods within those periods, with early application permitted for transactions that have not been previously reported. We will apply this guidance to all transactions completed subsequent to our adoption of these amendments.

Goodwill Impairment

In January 2017, FASB issued ASU 2017-04, Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment, which eliminates Step 2 from the goodwill impairment test. Step 2 required entities to compute the implied fair value of goodwill if it was determined that the carrying amount of a reporting unit exceeded its fair value. Under the amendments in this update, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount and should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit’s fair value. The goodwill impairment recognized should not exceed the total amount of goodwill allocated to that reporting unit.

Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. These amendments are effective for annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. We expect to apply these amendments for our annual goodwill impairment test as of November 30, 2017, or earlier if events or changes in circumstances indicate that an interim goodwill impairment test is necessary.

Other Income

In February 2017, FASB issued ASU 2017-05, Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20), which clarifies the scope of Subtopic 610-20 and adds guidance for partial sales of nonfinancial assets. Specifically, the amendments clarify that the guidance applies to all nonfinancial assets and in substance nonfinancial assets unless other specific guidance applies and defines "in substance financial asset" as an asset or group of assets for which substantially all of the fair value consists of nonfinancial assets and the group or subsidiary is not a business. These amendments also impact the accounting for partial sales of nonfinancial assets, whereby an entity that transfers its controlling interest in a nonfinancial asset, but retains a noncontrolling ownership interest, will measure the retained interest at fair value resulting in the full gain/loss recognition upon sale. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2017, with early adoption permitted. We are currently evaluating the effect of such amendments on our consolidated financial statements.

Stock Compensation – Scope of Modification Accounting

In May 2017, FASB issued ASU 2017-09, Compensation—Stock Compensation (Topic 718): Scope of Modification Accounting, which clarifies when changes to the terms or conditions of a share-based payment award must be accounted for as modifications. Under the new guidance, an entity will apply modification accounting only if the fair value, vesting conditions or the classification of the award changes as a result of the change in terms or conditions of a share-based payment award. In addition, the new guidance clarifies that regardless of whether an entity is required to apply modification accounting, the existing disclosure requirements and other aspects of GAAP associated with modifications continue to apply. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2017, with early adoption permitted. We early adopted the applicable amendments in second quarter of 2017 and will apply the new guidance prospectively to awards modified on or after the adoption date.

Financial Instruments with Down Round Features

In July 2017, FASB issued ASU 2017-11, Earnings Per Share (Topic 260); Distinguishing Liabilities from Equity (Topic 480); Derivatives and Hedging (Topic 815): (Part I) Accounting for Certain Financial Instruments with Down Round Features. (Part II) Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests with a Scope Exception. The amendments in this update are intended to simplify the accounting for certain equity-linked financial instruments and embedded features with down round features that result in the strike price being reduced on the basis of the pricing of future equity offerings. Under the new guidance, a down round feature will no longer need to be considered when determining whether certain financial instruments or embedded features should be classified as liabilities or equity instruments. That is, a down round feature will no longer preclude equity classification when assessing whether an instrument or embedded feature is indexed to an entity's own stock. In addition, the amendments clarify existing disclosure requirements for equity-classified instruments. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. We early adopted the applicable amendments in the second quarter of 2017 on a retrospective basis noting no effect on our consolidated financial statements.

Note 4 – Acquisitions and Divestitures

2017 Acquisitions

Permian Acquisition

On March 1, 2017, Targa completed the purchase of 100% of the membership interests of Outrigger Delaware Operating, LLC, Outrigger Southern Delaware Operating, LLC (together "New Delaware") and Outrigger Midland Operating, LLC ("New Midland" and together with New Delaware, the "Permian Acquisition").

We paid $484.1 million in cash at closing on March 1, 2017, and paid an additional $90.0 million in cash on May 30, 2017 (collectively, the "initial purchase price"). Subject to certain performance-linked measures and other conditions, additional cash of up to $935.0 million may be payable to the sellers of New Delaware and New Midland in potential earn-out payments that may occur in 2018 and 2019. The potential earn-out payments will be based upon a multiple of realized gross margin from contracts that existed on March 1, 2017.

New Delaware’s gas gathering and processing and crude gathering assets are located in Loving, Winkler, Pecos and Ward counties in Texas. The operations are backed by producer dedications of more than 145,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 14 years. The New Delaware assets include 70 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the New Delaware system. Since March 1, 2017, financial and statistical data of New Delaware have been included in Sand Hills operations.

New Midland’s gas gathering and processing and crude gathering assets are located in Howard, Martin and Borden counties in Texas. The operations are backed by producer dedications of more than 105,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 13 years. The New Midland assets include 10 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the New Midland system. Since March 1, 2017, financial and statistical data of New Midland have been included in SAOU operations.

New Delaware’s gas gathering and processing assets were connected to our Sand Hills system in the first quarter of 2017 and we expect that New Midland’s gas gathering and processing assets will be connected to our existing WestTX system during 2017. We believe connecting the acquired assets to our legacy Permian footprint creates operational and capital synergies, and will afford enhanced flexibility in serving our producer customers.

On January 26, 2017, we completed a public offering of 9,200,000 shares of our common stock (including the shares sold pursuant to the underwriters’ overallotment option) at a price to the public of $57.65, providing net proceeds of $524.2 million. We used the net proceeds from this public offering to fund the cash portion of the Permian Acquisition purchase price due upon closing and for general corporate purposes.

The acquired businesses contributed revenues of $36.4 million and a net loss of $12.6 million to us for the period from March 1, 2017 to June 30, 2017, and are reported in our Gathering and Processing segment. As of June 30, 2017, we had incurred $5.2 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, 2017.

Pro Forma Impact of Permian Acquisition on Consolidated Statement of Operations

The following summarized unaudited pro forma Consolidated Statement of Operations information for the six months ended June 30, 2017 and June 30, 2016 assumes that the Permian Acquisition occurred as of January 1, 2016. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma information may not be indicative of the results that would have occurred had we completed this acquisition as of January 1, 2016, or that would be attained in the future.

	June 30, 2017 Pro Forma	June 30, 2016 Pro Forma
Revenues	$3,994.4	$3,034.3
Net income (loss)	(41.2)	(36.0)

The pro forma consolidated results of operations amounts have been calculated after applying our accounting policies, and making the following adjustments to the unaudited results of the acquired businesses for the periods indicated:

- Reflect the amortization expense resulting from the preliminary estimate of the fair value of intangible assets recognized as part of the Permian Acquisition. For the purposes of preparing the pro forma adjustments we have assumed a 15-year life using the straight-line method. The amortization method and lives for the Permian Acquisition intangibles will be reviewed and possibly revised as we finalize the valuations.

- Reflect the change in depreciation expense resulting from the difference between the historical balances of the Permian Acquisition's property, plant and equipment, net, and the preliminary estimate of the fair value of property, plant and equipment acquired.

- Exclude $5.2 million of acquisition-related costs incurred as of June 30, 2017 from pro forma net income for the six months ended June 30, 2017. Pro forma net income for the six months ended June 30, 2016 was adjusted to include those charges.

• Reflect the income tax effects of the above pro forma adjustments.

The following table summarizes the consideration transferred to acquire New Delaware and New Midland:

Fair Value of Consideration Transferred:		
Cash paid, net of $3.3 million cash acquired	$	570.8
Contingent consideration valuation		416.3
Total	$	987.1

We accounted for the Permian Acquisition as an acquisition of a business under purchase accounting rules. The assets acquired and liabilities assumed related to the Permian Acquisition were recorded at their fair values as of the closing date of March 1, 2017. The fair values below are preliminary and subject to revisions pending the finalization of our review of the valuation. These and other estimates are subject to change as additional information becomes available and is assessed by us. The preliminary fair value of the assets acquired and liabilities assumed at the acquisition date is shown below:

Fair value determination:	March 1, 2017
Trade and other current receivables, net	$6.7
Other current assets	0.6
Property, plant and equipment	255.8
Intangible assets	692.3
Current liabilities	(14.1)
Other long-term liabilities	(0.8)
Total identifiable net assets	940.5
Goodwill	46.6
Total fair value of consideration transferred	$987.1

Under the acquisition method of accounting, the assets acquired and liabilities assumed are recognized at their estimated fair values, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill. Such excess of purchase price over the fair value of net assets acquired was approximately $46.6 million, which was recorded as goodwill. As of June 30, 2017, this determination is based on our preliminary valuation and is subject to revisions pending the finalization of our review of the valuation. As a result, goodwill is also preliminary. The preliminary goodwill is attributable to expected operational and capital synergies. The goodwill is expected to be amortizable for tax purposes. The attribution of the goodwill to reporting units for the purpose of required future impairment assessments will be completed in conjunction with our finalization of the fair value determination.

The preliminary fair value of assets acquired included trade receivables of $6.7 million, substantially all of which has been subsequently collected.

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 17 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

During the three months ended June 30, 2017, we recorded measurement period adjustments to our preliminary acquisition date fair values due to the refinement of our valuation models, assumptions and inputs, including forecasts of future volumes, capital expenditures and operating expenses. The measurement period adjustments are based upon information obtained about facts and circumstances that existed at the acquisition date that, if known, would have affected the measurement of the amounts recognized at that date. We have recognized these measurement period adjustments in the current reporting period, 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 March 1, 2017. During the three months ended June 30, 2017, the acquisition date fair value of contingent consideration liability decreased by $45.3 million, intangible assets increased by $66.7 million, and other assets, net, increased by $0.4 million, which resulted in a decrease in goodwill of $112.4 million. These adjustments resulted in an increase in depreciation and amortization expense of $0.4 million recorded in the three months ended June 30, 2017.

Contingent Consideration

A contingent consideration liability arising from potential earn-out payments in connection with the Permian Acquisition has been recognized at its preliminary fair value. We agreed to pay up to an additional $935.0 million in potential earn-out payments that may occur in 2018 and 2019. The preliminary acquisition date fair value of the potential earn-out payments of $416.3 million was recorded within Other long-term liabilities on our Consolidated Balance Sheets. Changes in the fair value of this liability, excluding any measurement period adjustments of the acquisition date fair value, are included in earnings. During the six months ended June 30, 2017, we recognized $1.1 million as Other expense related to the change in fair value of the contingent consideration. See Note 17 – Fair Value Measurements for additional discussion of the fair value methodology.

As of June 30, 2017, the fair value of the first potential earn-out payment of $40.6 million has been recorded as a component of accounts payable and accrued liabilities, which are current liabilities on our Consolidated Balance Sheets. As of June 30, 2017, the fair value of the second potential earn-out payment of $376.8 million has been recorded within Other long-term liabilities on our Consolidated Balance Sheets.

Flag City Acquisition

On May 9, 2017, we purchased all of the equity interests in Flag City Processing Partners, LLC ("FCCP") from Boardwalk Midstream, LLC (“Boardwalk”) and all of the equity interests in FCPP Pipeline, LLC from Boardwalk Field Services, LLC (“BFS”) for a base purchase price of $60.0 million subject to customary closing adjustments. The preliminary adjustment to the base purchase price paid to Boardwalk at closing was an additional $4.7 million. Final adjustments and settlement will occur within 90 days of closing. As part of the acquisition (the “Flag City Acquisition”), we acquired a natural gas processing plant with 150 MMcf/d of operating capacity (the “Flag City Plant”) located in Jackson County, Texas; 24 miles of gas gathering pipeline systems and related rights-of-ways located in Bee and Karnes counties in Texas; 102.1 acres of land surrounding the Flag City Plant; and a limited number of gas supply contracts.

The gas processing activities under the Flag City Plant contracts have been transferred to our Silver Oak Plants. We have shut down the Flag City Plant and intend to move the plant and its component parts to other Targa locations.

We accounted for this purchase as an asset acquisition and have capitalized less than $0.1 million of acquisition related costs as a component of the cost of assets acquired, which resulted in a preliminary allocation of $51.5 million of property, plant and equipment, $8.5 million of intangible assets for customer contracts and $4.7 million of current assets and liabilities, net.

Purchase of Outstanding Silver Oak II Interests

Effective as of June 1, 2017, we repurchased from SN Catarina, LLC (a subsidiary of Sanchez Energy Corp.) the remaining 10% interest in our consolidated Silver Oak II Gas processing facility and other related assets located in Bee County, Texas for a purchase price of $12.5 million. The change in our ownership interest was accounted for as an equity transaction representing the acquisition of a noncontrolling interest and no gain or loss was recognized in our Consolidated Statements of Operations as a result.

2017 Divestiture

Sale of Venice Gathering System, L.L.C.

Through our 76.8% ownership interest in Venice Energy Services Company, L.L.C. (“VESCO”), we have operated the Venice Gas Plant and the Venice gathering system. On April 4, 2017, VESCO entered into a purchase and sale agreement with Rosefield Pipeline Company, LLC, an affiliate of Arena Energy, LP, to sell its 100% ownership interests in Venice Gathering System, L.L.C. (“VGS”), a Delaware limited liability company engaged in the business of transporting natural gas in interstate commerce, under authorization granted by and subject to the jurisdiction of the Federal Energy Regulatory Commission (“FERC”), for approximately $0.4 million in cash. Additionally, the VGS asset retirement obligations (“ARO”) were assumed by the buyer. VGS owns and operates a natural gas gathering system in the Gulf of Mexico. Historically, VGS has been reported in our Gathering and Processing segment. After the sale of VGS, we continue to operate the Venice Gas Plant through our ownership in VESCO. Targa Midstream Services LLC will continue to operate the Venice gathering system for up to four months after closing pursuant to a Transition Services Agreement with VGS.

As a result of the April 4, 2017 sale, we recognized a loss of $16.1 million in our Consolidated Statements of Operations for the three months ended March 31, 2017 as part of Other operating (income) expense to impair our basis in the VGS net assets to its fair value. As such, the VGS divestiture had no impact on our net income for the three months ended June 30, 2017 and its primary impact was the removal of the VGS assets and liabilities from our Consolidated Balance Sheet.

Note 5 — Inventories

	June 30, 2017	December 31, 2016
Commodities	$187.8	$ 126.9
Materials and supplies	9.9	10.8
	$197.7	$ 137.7

Note 6 — Property, Plant and Equipment and Intangible Assets

Property, Plant and Equipment

	June 30, 2017	December 31, 2016	Estimated Useful Lives (In Years)
Gathering systems	$6,849.2	$6,626.8	5 to 20
Processing and fractionation facilities	3,561.2	3,390.2	5 to 25
Terminaling and storage facilities	1,233.6	1,205.0	5 to 25
Transportation assets	342.7	451.4	10 to 25
Other property, plant and equipment	284.0	274.2	3 to 25
Land	122.4	121.3	—
Construction in progress	920.5	449.8	—
Property, plant and equipment	13,313.6	12,518.7	
Accumulated depreciation	(3,086.8)	(2,827.7)	
Property, plant and equipment, net	$10,226.8	$9,691.0	
Intangible assets	$2,737.4	$2,036.6	10 to 20
Accumulated amortization	(472.7)	(382.6)	
Intangible assets, net	$2,264.7	$1,654.0	

Intangible Assets

Intangible assets consist of customer contracts and customer relationships acquired in the Permian and Flag City Acquisitions in 2017, the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively, the “Atlas mergers”) and our Badlands 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 intangible assets acquired in the Permian Acquisition were recorded at a preliminary fair value of $692.3 million pending completion of final valuations. For the purposes of preparing the accompanying financial statements (which include four months of amortization of these intangible assets), we are amortizing these intangible assets over a 15-year life using the straight-line method. The amortization method and lives for the Permian Acquisition intangibles will be reviewed and possibly revised as we finalize the valuations over the upcoming months.

The intangible assets acquired in the Flag City Acquisition were recorded at a preliminary fair value of $8.5 million pending completion of the final valuation. For the purposes of preparing the accompanying financial statements (which include two months of amortization of these intangible assets), we are amortizing these intangible assets over a 10-year life using the straight-line method. The amortization method and lives for the Flag City Acquisition intangibles will be reviewed and possibly revised as we finalize the valuation.

The intangible assets acquired in the Atlas mergers are being amortized over a 20-year life using the straight-line method, as a reliably determinable pattern of amortization could not be identified. 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 over a 20-year life.

The estimated annual amortization expense for intangible assets, including the provisional Permian and Flag City valuations is approximately $188.4 million, $182.7 million, $171.7 million, $159.5 million and $149.6 million for each of the years 2017 through 2021.

The changes in our intangible assets are as follows:

Balance at December 31, 2016	$1,654.0
Additions from Permian Acquisition	692.3
Additions from Flag City Acquisition	8.5
Amortization	(90.1)
Balance at June 30, 2017	$2,264.7

Note 7 – 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. During the first quarter of 2016, we finalized our 2015 impairment assessment and recorded additional impairment expense of $24.0 million on our Consolidated Statement of Operations. The impairment of goodwill was 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.

Changes in the net book value of our goodwill are as follows:

	WestTX	SouthTX	Permian	Total
Balance at December 31, 2016, net	$ 174.7	$ 35.3	$ —	$210.0
Permian Acquisition, March 1, 2017 (preliminary valuation)	—	—	46.6	46.6
Balance at June 30, 2017, net	$ 174.7	$ 35.3	$ 46.6	$256.6

Note 8 – 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: a 75% interest in T2 LaSalle, a gas gathering company; a 50% interest in T2 Eagle Ford, a gas gathering company; and a 50% interest in T2 EF Cogen ("Cogen"), which owns a cogeneration facility, (together the "T2 Joint Ventures"). The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 LaSalle and T2 Eagle Ford gathering companies have capacity lease agreements with the joint interest owners, which cover their costs of operations (excluding depreciation and amortization). 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.

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

	GCF	T2 LaSalle	T2 Eagle Ford	T2 EF Cogen	Total
Balance at December 31, 2016	$46.1	$ 58.6	$118.6	$17.5	$240.8
Equity earnings (loss)	4.0	(2.4)	(5.4)	(13.0)	(16.8)
Cash distributions (1)	(7.2)	—	—	—	(7.2)
Contributions for expansion projects (2)	—	0.4	1.1	0.1	1.6
Balance at June 30, 2017	$42.9	$ 56.6	$114.3	$4.6	$218.4

(1) Includes $3.2 million in distributions received from GCF in excess of our share of cumulative earnings for the six months ended June 30, 2017. Such excess distributions are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows in the period in which they occur.
(2) Includes a $1.0 million contribution of property, plant and equipment to T2 Eagle Ford.

Our equity loss for the six months ended June 30, 2017 includes the effect of an impairment in the carrying value of our investment in T2 EF Cogen. As a result of the decrease in current and expected future utilization of the underlying cogeneration assets, we have determined that factors indicate that a decrease in the value of our investment occurred that was other than temporary. As a result of this evaluation, we recorded an impairment loss of approximately $12.0 million in the first quarter of 2017, which represented our proportionate share (50%) of an impairment charge recorded by the joint venture, as well as our impairment of the unamortized excess fair value resulting from the Atlas mergers.

The carrying values of the T2 gathering joint ventures include the effects of the Atlas mergers purchase accounting, which determined fair values for the joint ventures as of the date of acquisition. As of June 30, 2017, $26.9 million of unamortized excess fair value over the T2 LaSalle and T2 Eagle Ford capital accounts remained. These basis differences, which are attributable to the underlying depreciable tangible gathering assets, are being amortized on a straight-line basis as components of equity earnings over the estimated 20-year useful lives of the underlying assets.

Note 9 — Accounts Payable and Accrued Liabilities

	June 30, 2017	December 31, 2016
Commodities	$482.7	$ 574.4
Other goods and services	192.2	117.0
Interest	53.8	52.3
Income and other taxes	45.0	24.2
Permian Acquisition contingent consideration, estimated current portion	40.6	—
Compensation and benefits	29.8	37.2
Preferred Series A dividends payable	22.9	22.9
Other	19.0	15.5
	$886.0	$ 843.5

Accounts payable and accrued liabilities includes $43.1 million and $30.5 million of liabilities to creditors to whom we have issued checks that remain outstanding as of June 30, 2017 and December 31, 2016. The estimated current portion of the Permian Acquisition contingent consideration represents the fair value as of June 30, 2017, of the first potential earn-out payment that may occur in May 2018. The estimated remaining portion would be payable in May 2019 and is recorded within Other long-term liabilities on our Consolidated Balance Sheets.

Note 10 — Debt Obligations

	June 30, 2017	December 31, 2016
Current:		
Obligations of the Partnership: (1)		
Accounts receivable securitization facility, due December 2017	$ 250.0	$ 275.0
Senior unsecured notes, 5% fixed rate, due January 2018 (2)	250.5	—
	500.5	275.0
Debt issuance costs, net of amortization	(0.4)	—
Current debt obligations	500.1	275.0
Long-term:		
TRC obligations:		
TRC Senior secured revolving credit facility, variable rate, due February 2020 (3)	435.0	275.0
TRC Senior secured term loan, variable rate, due February 2022	—	160.0
Unamortized discount	—	(2.2)
Obligations of the Partnership: (1)		
Senior secured revolving credit facility, variable rate, due October 2020 (4)	—	150.0
Senior unsecured notes:		
5% fixed rate, due January 2018 (2)	—	250.5
4 % fixed rate, due November 2019	749.4	749.4
6 % fixed rate, due August 2022	—	278.7
5¼% fixed rate, due May 2023	559.6	559.6
4¼% fixed rate, due November 2023	583.9	583.9
6¾% fixed rate, due March 2024	580.1	580.1
5 % fixed rate, due February 2025	500.0	500.0
5 % fixed rate, due February 2027	500.0	500.0
TPL notes, 4¾% fixed rate, due November 2021 (5)	6.5	6.5
TPL notes, 5 % fixed rate, due August 2023 (5)	48.1	48.1
Unamortized premium	0.4	0.5
	3,963.0	4,640.1
Debt issuance costs, net of amortization	(25.5)	(34.1)
Long-term debt	3,937.5	4,606.0
Total debt obligations	$ 4,437.6	$ 4,881.0
Irrevocable standby letters of credit:		
Letters of credit outstanding under the TRC Senior secured credit facility (3)	$ —	$ —
Letters of credit outstanding under the Partnership senior secured revolving credit facility (4)	20.4	13.2
	$ 20.4	$ 13.2

(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 or Targa Pipeline Partners, L.P. (“TPL”).
(2) The 5% Notes were reclassified to a current liability in January 2017. Prior to that date, the notes were classified as a long-term liability on our Consolidated Balance Sheets.
(3) As of June 30, 2017, availability under TRC’s $670.0 million senior secured revolving credit facility (“TRC Revolver”) was $235.0 million.
(4) As of June 30, 2017, availability under the Partnership’s $1.6 billion senior secured revolving credit facility (“TRP Revolver”) was $1,579.6 million.
(5) TPL notes are 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, 2017:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC Revolver	2.5% - 4.5%	2.7%
TRC Senior secured term loan (1)	5.75%	5.75%
TRP Revolver	3.0% - 5.3%	3.2%
Partnership's accounts receivable securitization facility	1.8% - 2.2%	1.9%

(1) The TRC Senior secured term loan is a Eurodollar rate loan with an interest rate of LIBOR (with a LIBOR floor of 1%) plus an applicable rate of 4.75%.

Compliance with Debt Covenants

As of June 30, 2017, we were in compliance with the covenants contained in our various debt agreements.

Securitization Facility

On February 23, 2017, we amended the Partnership's accounts receivable securitization facility ("Securitization Facility") to increase the facility size from $275.0 million to $350.0 million. As of June 30, 2017, there was $250.0 million outstanding under the Securitization Facility.

Debt Repurchases & Extinguishments

In March 2017, we repaid the entirety of the TRC Senior secured term loan in the amount of $160.0 million. The repayment resulted in write offs of $2.1 million of discount and $3.7 million of debt issuance costs, which are reflected as loss from financing activities on the Consolidated Statements of Operations.

In June 2017, the Partnership redeemed its outstanding 6 % Senior Notes due August 2022 (“6 % Senior Notes”), totaling $278.7 million in aggregate principal amount, at a price of 103.188% plus accrued interest through the redemption date. The redemption resulted in a $10.7 million loss, which is reflected as loss from financing activities on the Consolidated Statements of Operations, consisting of premiums paid of $8.9 million and a non-cash loss to write-off $1.8 million of unamortized debt issuance costs.

Note 11 — Other Long-term Liabilities

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

	June 30, 2017	December 31, 2016
Asset retirement obligations	$49.1	$ 64.6
Mandatorily redeemable preferred interests	77.2	68.5
Deferred revenue	68.3	69.8
Permian Acquisition contingent consideration, noncurrent portion	376.8	—
Other liabilities	17.0	12.2
Total long-term liabilities	$588.4	$ 215.1

Asset Retirement Obligations

Our ARO primarily relate to certain gas gathering pipelines and processing facilities. The changes in our ARO are as follows:

Balance at December 31, 2016	$64.6
Additions (1)	0.8
Reduction due to sale of VGS	(21.6)
Change in cash flow estimate	3.1
Accretion expense	2.2
Balance at June 30, 2017	$49.1

(1) Amount reflects AROs assumed from the Permian Acquisition.

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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 until at least 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, 2017.

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

Balance at December 31, 2016	$68.5
Income attributable to mandatorily redeemable preferred interests	1.8
Change in estimated redemption value included in interest expense	6.9
Balance at June 30, 2017	$77.2

Deferred Revenue

We have certain long-term contractual arrangements under which we have received consideration, but which require future performance by Targa. These arrangements result in deferred revenue, which will be recognized over the periods that performance will be provided.

Deferred revenue includes consideration received related to the construction and operation of a crude oil and condensate splitter. On December 27, 2015, Targa Terminals LLC and Noble Americas Corp., a subsidiary of Noble Group Ltd., entered into a long-term, fee-based agreement (“Splitter Agreement”) under which we will build and operate a 35,000 barrel per day crude oil and condensate splitter at our Channelview Terminal on the Houston Ship Channel (“Channelview Splitter”) and provide approximately 730,000 barrels of storage capacity. The Channelview Splitter will have the capability to split approximately 35,000 barrels per day of crude oil 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 project is expected to be completed by the first half of 2018, and has an estimated total cost of approximately $140.0 million. The first annual advance payment due under the Splitter Agreement was received in October 2016 and has been recorded as deferred revenue, as the Splitter Agreement requires future performance by Targa. The Splitter Agreement provides that subsequent annual payments of $43.0 million (subject to an annual inflation factor) are to be paid to Targa through 2022. The deferred revenue will be recognized over the contractual period that future performance will be provided, currently anticipated to commence with start-up in 2018 and continuing through 2025.

Deferred revenue also includes consideration received in a 2015 amendment (the “gas contract amendment”) to a gas gathering and processing agreement. We measured the estimated fair value of the assets transferred to us using significant other observable inputs representative of a Level 2 fair value measurement. Because the gas contract amendment will require future performance by Targa, we have recorded the consideration received as deferred revenue. The deferred revenue related to this amendment is being recognized on a straight-line basis through the end of the agreement’s term in 2030.

Deferred revenue also includes consideration received for other construction activities of facilities connected to our systems. The deferred revenue related to these other construction activities will be recognized over the periods that future performance will be provided, which extend through 2023.

The following table shows the components of deferred revenue:

	June 30, 2017	December 31, 2016
Splitter agreement	$43.0	$ 43.0
Gas contract amendment	19.0	19.7
Other deferred revenue	6.3	7.1
Total deferred revenue	$68.3	$ 69.8

The following table shows the changes in deferred revenue:

Balance at December 31, 2016	$69.8
Additions	-
Revenue recognized	(1.5)
Balance at June 30, 2017	$68.3

Contingent Consideration

A contingent consideration liability arising from potential earn-out payments in connection with the Permian Acquisition has been recognized at its preliminary fair value. We agreed to pay up to an additional $935.0 million in potential earn-out payments that may occur in 2018 and 2019. The first potential earn-out payment would occur in May 2018 and the second potential earn-out payment would occur in May 2019. The preliminary acquisition date fair value of the potential earn-out payments of $461.6 million was recorded within Other long-term liabilities on our Consolidated Balance Sheets as of March 31, 2017. During the second quarter of 2017, we recorded a measurement period adjustment to reduce the preliminary acquisition date fair value of the potential earn-out payment to $416.3 million. Subsequent changes in the fair value of this liability, excluding any measurement period adjustments of the acquisition date fair value, are included in earnings.

For the four months ended June 30, 2017, we had an increase in the fair value of this liability of $1.1 million, bringing the total Permian Acquisition contingent consideration to $417.4 million. As of June 30, 2017, the fair value of the first potential earn-out payment of $40.6 million has been recorded as a component of accounts payable and accrued liabilities, which are current liabilities on our Consolidated Balance Sheets. As of June 30, 2017, the fair value of the second potential earn-out payment of $376.8 million has been recorded within Other long-term liabilities on our Consolidated Balance Sheets. See Note 17 – Fair Value Measurements for additional discussion of the fair value methodology.

The following table shows the changes in contingent consideration:

Balance at March 1, 2017 (acquisition date)	$461.6
Measurement period adjustment	(45.3)
Increase in fair value since acquisition date	1.1
Balance at June 30, 2017	$417.4
Less: Current portion	(40.6)
Long-term balance at June 30, 2017	$376.8

Note 12 – 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 has 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 Series A Preferred ranks senior to the common outstanding stock with respect to the payment of dividends and distributions in liquidation. The Company may 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. We have not made an election to PIK through June 30, 2017. The Series A Preferred has 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 volume weighted average price ("VWAP") prior to the February 18, 2016 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 Series A Preferred does not qualify as a 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 were 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. See exercise of the Warrants in Note 13 – Common Stock and Related Matters.

Net cash proceeds were allocated on a relative fair value basis to the Series A Preferred, Series A Warrants and Series B Warrants. The $178.1 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 $787.1 million allocated to the Series A Preferred was allocated to additional paid-in capital to give effect to the intrinsic value of a beneficial conversion feature ("BCF").

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

		Allocation of Proceeds			
			Additional Paid-in Capital		
		Series A Preferred	Series A Warrants	Series B Warrants	Beneficial Conversion Feature
Gross proceeds	$994.1				
Transaction fees	(24.8)				
Net Proceeds- Initial Relative Fair Value Allocation	$969.3	$787.1	$135.7	$ 46.5	$ —
Allocation to BCF		(614.4)	—	—	614.4
Per balance sheet upon issuance		$172.7	$135.7	$ 46.5	$ 614.4

Beneficial Conversion Feature

ASC 470-20-20 – Debt – Debt with conversion and Other Options ("ASC 470-20") defines BCF as a nondetachable conversion feature that is in the money at the issuance date. We were 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. Upon exercise of our redemption rights, any previously recognized accretion of deemed dividends would be reversed in the period of redemption and reflected as income attributable to common shareholders in our Consolidated Statement of Operations and related per share amounts.

Preferred Stock Dividends

As of June 30, 2017, we have accrued cumulative preferred dividends of $22.9 million, which will be paid on August 14, 2017. During the six months ended June 30, 2017, we paid $45.8 million of dividends to preferred shareholders, and recorded deemed dividends of $12.5 million attributable to accretion of the preferred discount resulting from the BCF accounting described above. Such accretion is included in the book value of the Series A Preferred Stock.

Note 13 — Common Stock and Related Matters

Public Offerings of Common Stock

On January 26, 2017, we completed a public offering of 9,200,000 shares of our common stock (including the shares sold pursuant to the underwriters' overallotment option) at a price to the public of $57.65, providing net proceeds of $524.2 million. We used the net proceeds from this public offering to fund the cash portion of the Permian Acquisition purchase price due upon closing and for general corporate purposes.

For the six months ended June 30, 2017, we issued 4,521,310 shares of common stock under our Equity Distribution Agreement entered into in December 2016 (the "December 2016 EDA"), receiving net proceeds of $257.2 million. As of June 30, 2017 we have $411.2 million remaining under the December 2016 EDA.

On May 9, 2017, we entered into an equity distribution agreement under the May 2016 Shelf (the "May 2017 EDA"), pursuant to which we may sell through our sales agents, at our option, up to an aggregated amount of $750.0 million of our common stock. For the six months ended June 30, 2017, no shares of common stock have been issued under the May 2017 EDA.

On June 1, 2017, we completed a public offering of 17,000,000 shares of our common stock at a price to the public of $46.10, providing net proceeds after underwriting discounts, commissions and other expenses of $777.3 million. We used the net proceeds from this public offering to fund a portion of the capital expenditures related to the construction of the new NGL pipeline connecting the Permian Basin and our Mont Belvieu facility, which will be known as "Grand Prix," repay outstanding borrowings under our credit facilities, redeem the Partnership's 6 % Senior Notes, and for general corporate purposes.

Warrants

During 2016, 19,983,843 warrants were exercised and net settled for 11,336,856 shares of common stock. For the six months ended June 30, 2017, no detachable Warrants were exercised. As a result, Series A Warrants exercisable into a maximum of 67,392 shares of common stock and Series B Warrants exercisable into maximum of 32,496 shares of common stock were outstanding as of June 30, 2017.

Dividends

The following table details the dividends declared and/or paid by us to common shareholders for the six months ended June 30, 2017.

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock (per share amounts)
June 30, 2017	August 15, 2017	$ 198.6	$ 196.2	$ 2.4	$ 0.91000
March 31, 2017	May 16, 2017	182.8	180.3	2.5	0.91000
December 31, 2016	February 15, 2017	178.3	176.5	1.8	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 — Partnership Units and Related Matters

Distributions

As a result of the TRC/TRP Merger in 2016, we are entitled to receive all available Partnership distributions on the Partnership’s common units after payment of preferred distributions each quarter. The Partnership has discretion under the Third A&R Partnership Agreement as to whether to distribute all available cash for any period. See Note 2 – Basis of Presentation.

The following details the distributions declared or paid by the Partnership for the six months ended June 30, 2017.

Three Months Ended	Date Paid Or to Be Paid	Total Distributions	Distributions to Targa Resources Corp.
June 30, 2017	August 10, 2017	$ 225.4	$ 222.6
March 31, 2017	May 11, 2017	209.6	206.8
December 31, 2016	February 10, 2017	198.1	195.3

Contributions

Subsequent to December 1, 2016, the effective date of the Third A&R Partnership Agreement, no units will be issued for capital contributions to the Partnership, but all capital contributions will continue to be allocated 98% to the limited partner and 2% to the general partner. For the six months ended June 30, 2017, we made total capital contributions to the Partnership of $1,605.0 million.

Preferred Units

In October 2015, the Partnership completed an offering of 5,000,000 Preferred Units at a price of $25.00 per unit. The Preferred Units are listed on the NYSE under the symbol "NGLS PRA."

Distributions on the Partnership's Preferred Units are cumulative from the date of original issue in October 2015 and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of the Partnership's general partner. Distributions on the Preferred Units are payable out of amounts legally available at a rate equal to 9.0% per annum. On and after November 1, 2020, distributions on the Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%.

The Partnership paid $2.8 million and $5.6 million of distributions to the holders of preferred units ("Preferred Unitholders") for the three and six months ended June 30, 2017. The Preferred Units are reported as noncontrolling interests in our financial statements.

Subsequent Event

In July 2017, the board of directors of the general partner of the Partnership declared a cash distribution of $0.1875 per Preferred Unit. This distribution will be paid on August 15, 2017.

Note 15 — 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,	
	2017	2016	2017	2016
Net income	$70.6	$(14.6)	$(39.9)	$(15.2)
Less: Net income attributable to noncontrolling interests	13.0	8.6	21.8	10.7
Less: Dividends on preferred stock	29.2	29.4	58.3	33.2
Net income attributable to common shareholders for basic earnings per share	$28.4	$(52.6)	$(120.0)	$(59.1)
Weighted average shares outstanding - basic	203.7	161.6	197.8	134.1
Net income available per common share - basic	$0.14	$(0.33)	$(0.61)	$(0.44)
Weighted average shares outstanding	203.7	161.6	197.8	134.1
Dilutive effect of common stock equivalents (1)	1.3	—	—	—
Weighted average shares outstanding - diluted	205.0	161.6	197.8	134.1
Net income available per common share - diluted	$0.14	$(0.33)	$(0.61)	$(0.44)

(1) The dilutive effects of common stock equivalents were computed using the treasury method for warrants and unvested stock awards, and the if-converted method for the convertible preferred stock. Under the if-converted method, the dividends on the convertible preferred stock are added back to the numerator for the purposes of the diluted earnings per share calculation. For the periods with net income attributable to common shareholders, the anti-dilution sequencing rule was applied from the most dilutive to the least dilutive potential common shares.

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,	
	2017	2016	2017	2016
Unvested restricted stock awards	0.2	0.6	1.2	0.3
Warrants to purchase common stock	—	9.3	0.1	5.0
Series A preferred stock (1)	46.5	46.5	46.5	27.3

(1) The Series A Preferred has 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. See Note 12 – Preferred Stock.

Note 16 — 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, NGL, and condensate equity volumes in our Gathering and Processing operations that result from percent-of-proceeds processing arrangements and (ii) future commodity purchases and sales in our Logistics and Marketing segment by entering into derivative instruments. 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 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 TPL derivative contracts with a fair value of $102.1 million as of February 27, 2015 (the “acquisition date”), were novated to us and included in the acquisition date fair value of assets acquired. We received derivative settlements of $1.9 million and $4.9 million for the three and six months ended June 30, 2017 and $6.3 million and $15.1 million for the three and six months ended June 30, 2016, related to these novated contracts. From the acquisition date through June 30, 2017, we have received derivative settlements of $99.5 million. The remainder of the novated contracts will settle by the end of 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL 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, we recorded ineffectiveness gains (losses) of less than $(0.1) million and $0.1 million for the three and six months ended June 30, 2017 and $(0.2) million and less than $0.1 million for the three and six months ended June 30, 2016, related to otherwise qualifying TPL derivatives, which are primarily natural gas swaps.

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.

At June 30, 2017, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2017	2018	2019
Natural Gas	Swaps	MMBtu/d	154,828	115,327	76,136
Natural Gas	Basis Swaps	MMBtu/d	121,739	3,226	-
Natural Gas	Futures	MMBtu/d	-	1,103	-
Natural Gas	Options	MMBtu/d	22,900	9,486	-
NGL	Swaps	Bbl/d	16,682	7,208	5,889
NGL	Futures	Bbl/d	18,587	7,616	-
NGL	Options	Bbl/d	2,007	2,986	410
Condensate	Swaps	Bbl/d	2,690	2,190	1,063
Condensate	Options	Bbl/d	1,380	691	590

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, 2017		Fair Value as of December 31, 2016	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 35.4	$ 8.6	$ 16.7	$ 48.6
	Long-term	17.3	5.5	5.1	26.1
Total derivatives designated as hedging instruments		$ 52.7	$ 14.1	$ 21.8	$ 74.7
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 0.3	$ 0.9	$ 0.1	$ 0.5
Total derivatives not designated as hedging instruments		$ 0.3	$ 0.9	$ 0.1	$ 0.5
Total current position		$ 35.7	$ 9.5	$ 16.8	$ 49.1
Total long-term position		17.3	5.5	5.1	26.1
Total derivatives		$ 53.0	$ 15.0	$ 21.9	$ 75.2

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

	Gross Presentation			Pro forma net presentation	
June 30, 2017	Asset	Liability	Collateral	Asset	Liability
Current Position					
Counterparties with offsetting positions or collateral	$34.6	$ (9.2)	$ (5.5)	$26.0	$ (6.1)
Counterparties without offsetting positions - assets	1.1	-	-	1.1	-
Counterparties without offsetting positions - liabilities	-	(0.3)	-	-	(0.3)
	35.7	(9.5)	(5.5)	27.1	(6.4)
Long Term Position					
Counterparties with offsetting positions or collateral	16.5	(4.6)	-	11.9	-
Counterparties without offsetting positions - assets	0.8	-	-	0.8	-
Counterparties without offsetting positions - liabilities	-	(0.9)	-	-	(0.9)
	17.3	(5.5)	-	12.7	(0.9)
Total Derivatives					
Counterparties with offsetting positions or collateral	51.1	(13.8)	(5.5)	37.9	(6.1)
Counterparties without offsetting positions - assets	1.9	-	-	1.9	-
Counterparties without offsetting positions - liabilities	-	(1.2)	-	-	(1.2)
	$53.0	$ (15.0)	$ (5.5)	$39.8	$ (7.3)

	Gross Presentation			Pro forma net presentation	
December 31, 2016	Asset	Liability	Collateral	Asset	Liability
Current Position					
Counterparties with offsetting positions or collateral	$16.8	$ (46.1)	$ 7.0	$5.7	$ (28.0)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(3.0)	-	-	(3.0)
	16.8	(49.1)	7.0	5.7	(31.0)
Long Term Position					
Counterparties with offsetting positions or collateral	5.1	(18.7)	-	-	(13.6)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(7.4)	-	-	(7.4)
	5.1	(26.1)	-	-	(21.0)
Total Derivatives					
Counterparties with offsetting positions or collateral	21.9	(64.8)	7.0	5.7	(41.6)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(10.4)	-	-	(10.4)
	$21.9	$ (75.2)	$ 7.0	$5.7	$ (52.0)

Our payment obligations in connection with a majority of these hedging transactions are secured by a first priority lien in the collateral securing the TRP Revolver that ranks equal in right of payment with liens granted in favor of the Partnership’s senior secured lenders. Some of our hedges are futures contracts executed through a broker that clears the hedges through an exchange. We maintain a margin deposit with the broker in an amount sufficient enough to cover the fair value of our open futures positions. The margin deposit is considered collateral, which is located within other current assets on our Consolidated Balance Sheets and is not offset against the fair values of our derivative instruments.

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 $38.0 million as of June 30, 2017. 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 margined daily and do not require any credit adjustment.

The following tables reflect amounts recorded in Other Comprehensive Income 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	2017	2016	2017	2016
Commodity contracts	$ 29.8	$ (60.2)	$ 96.0	$ (53.5)

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2017	2016	2017	2016
Revenues	$ 5.7	$ 18.3	$ (0.4)	$ 42.4

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			
Derivatives Not Designated as Hedging Instruments	Recognized in Income on Derivatives	Three Months Ended June 30,		Six Months Ended June 30,	
		2017	2016	2017	2016
Commodity contracts	Revenue	$(0.3)	$(0.3)	$(1.0)	$ 1.6

Based on valuations as of June 30, 2017, we expect to reclassify commodity hedge related deferred gains of $35.4 million included in accumulated other comprehensive income into earnings before income taxes through the end of 2019, with $23.7 million of gains to be reclassified over the next twelve months.

See Note 17 – Fair Value Measurements for additional disclosures related to derivative instruments and hedging activities.

Note 17 — 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, 2017, a net asset position of $38.0 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 $31.1 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 $107.7 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:

- The TRC Revolver, TRP Revolver, and the Partnership's accounts receivable securitization facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and
- Our term loan (prior to its repayment) and the Partnership's senior unsecured notes are based on quoted market prices derived from trades of the debt.

Contingent consideration liabilities related to business acquisitions are carried at fair value.

Fair Value Hierarchy

We categorize the inputs to the fair value measurements of financial assets and liabilities at each balance sheet reporting date 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, 2017				
	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)	$51.1	$51.1	$ —	$45.5	$5.6
Liabilities from commodity derivative contracts (1)	13.1	13.1	—	11.0	2.1
Permian Acquisition contingent consideration (2)	417.4	417.4	—	—	417.4
TPL contingent consideration (3)	2.7	2.7	—	—	2.7
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	98.7	98.7	—	—	—
TRC Revolver	435.0	435.0	—	435.0	—
TRC term loan	—	—	—	—	—
TRP Revolver	—	—	—	—	—
Partnership's Senior unsecured notes	3,778.5	3,869.7	—	3,869.7	—
Partnership's accounts receivable securitization facility	250.0	250.0	—	250.0	—

	December 31, 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)	$21.0	$21.0	$ —	$19.6	$1.4
Liabilities from commodity derivative contracts (1)	74.2	74.2	—	69.3	4.9

TPL contingent consideration (3)	2.6	2.6	—	—	2.6
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	73.5	73.5	—	—	—
TRC Revolver	275.0	275.0	—	275.0	—
TRC term loan	157.8	158.4	—	158.4	—
TRP Revolver	150.0	150.0	—	150.0	—
Partnership's Senior unsecured notes	4,057.3	4,101.6	—	4,101.6	—
Partnership's accounts receivable securitization facility	275.0	275.0	—	275.0	—

(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 16 – 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) We have a contingent consideration liability related to the Permian Acquisition, which is carried at fair value. See Note 4 – Acquisitions and Divestitures.
(3) We have a contingent consideration liability for TPL's previous acquisition of a gas gathering system and related assets, which is carried at fair value.

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 implied volatilities or 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, 2017, we had 27 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 (i) the forward natural gas liquids pricing curves, for which a significant portion of the derivative's term is beyond available forward pricing and (ii) implied volatilities, which are unobservable as a result of inactive natural gas liquids options trading. 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 Permian Acquisition contingent consideration was determined using a Monte-Carlo simulation model. Significant inputs used in the fair value measurement include expected gross margin (calculated in accordance with the terms of the purchase and sale agreements), term of the earn-out period, risk adjusted discount rate and volatility associated with the underlying assets. A significant decrease in expected gross margin during the earn-out period, or significant increase in the discount rate or volatility would result in a lower fair value estimate. The fair value of the TPL contingent consideration was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures. The inputs for both models are not observable; therefore, the entire valuations of the contingent considerations are categorized in Level 3. Changes in the fair value of these liabilities are included in Other income (expense) 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	Contingent

	Derivative Contracts Asset/(Liability)	Liability
Balance, December 31, 2016	$ (3.6)	$ (2.6)
Change in fair value of TPL contingent consideration	-	(0.1)
Fair value of Permian Acquisition contingent consideration (1)	-	(417.4)
New Level 3 derivative instruments	(0.3)	-
Transfers out of Level 3 (2)	1.6	-
Settlements included in Revenue	0.2	-
Unrealized gain/(loss) included in OCI	5.6	-
Balance, June 30, 2017	$ 3.5	$ (420.1)

(1) Represents the June 30, 2017 balance of the contingent consideration that arose as part of the Permian Acquisition in Q1 2017. See Note 4 – Acquisitions and Divestitures for discussion of the initial fair value.

(2) Transfers relate to long-term over-the-counter swaps for NGL products for which observable market prices became available for substantially their full term.

Note 18 – Contingencies

Legal Proceedings

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

Note 19 – Other Operating (Income) Expense

Other operating (income) expense is comprised of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
(Gain) loss on sale or disposal of assets (1)	$0.1	$-	$16.2	$0.9
Miscellaneous business tax	0.2	0.1	0.3	0.2
	$0.3	$0.1	$16.5	$1.1

(1) Comprised primarily of a $16.1 million loss in the first quarter of 2017 due to the reduction in the carrying value of our ownership interest in VGS in connection with the April 4, 2017 sale.

Note 20 - Supplemental Cash Flow Information

	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash:		
Interest paid, net of capitalized interest (1)	$ 109.2	$ 142.2
Income taxes paid, net of refunds	(67.8)	1.1
Non-cash investing activities:		
Deadstock commodity inventory transferred to property, plant and equipment	$ 8.3	$ 16.9
Impact of capital expenditure accruals on property, plant and equipment	80.0	(16.8)
Transfers from materials and supplies inventory to property, plant and equipment	1.5	0.9
Contribution of property, plant and equipment to investment in unconsolidated affiliates.	1.0	—
Change in ARO liability and property, plant and equipment due to revised cash flow estimate	3.1	(9.1)
Non-cash financing activities:		
Reduction of Owner's Equity related to accrued dividends on unvested equity awards under share compensation arrangements	$ 4.6	$ 4.9
Accrued tax withholding obligations	1.5	—
Allocation of Series A Preferred Stock net book value of BCF to additional paid-in capital	—	614.4
Accrued deemed dividends of Series A Preferred Stock	12.5	6.5
Change in accrued dividends of Series A Preferred Stock	—	22.9
Impact of accounting standard adoption recorded in retained earnings	56.1	—
Accrued distribution to noncontrolling interests	0.3	—
Non-cash balance sheet movements related to the Permian Acquisition (See Note 4 - Acquisitions and Divestitures):		
Contingent consideration recorded at the acquisition date	$ 416.3	$ —
Non-cash balance sheet movements related to the TRC/TRP Merger:		
Prepaid transaction costs reclassified 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

(1) Interest capitalized on major projects was $4.1 million and $6.3 million for the six months ended June 30, 2017 and 2016.

Note 21 — Segment Information

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

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 segment 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, 2017				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$177.5	$ 1,440.3	$6.0	$ —	$1,623.8
Fees from midstream services	132.3	111.6	—	—	243.9
	309.8	1,551.9	6.0	—	1,867.7
Intersegment revenues					
Sales of commodities	712.4	81.8	—	(794.2)	—
Fees from midstream services	1.4	7.1	—	(8.5)	—
	713.8	88.9	—	(802.7)	—
Revenues	$1,023.6	$ 1,640.8	$6.0	$ (802.7)	$1,867.7
Operating margin	$173.5	$ 112.4	$6.0	$ —	$291.9
Other financial information:					
Total assets (1)	$10,845.2	$ 2,918.5	$46.7	$ 108.0	$13,918.4
Goodwill	$256.6	$ —	$—	$ —	$256.6
Capital expenditures	$295.8	$ 136.1	$—	$ 2.6	$434.5

(1) Corporate assets at the segment level primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	Three Months Ended June 30, 2016				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and	Total

				Eliminations	
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, prepaids and debt issuance costs for our revolving credit facilities.

	Six Months Ended June 30, 2017				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$344.3	$ 3,132.5	$4.9	$ —	$3,481.7
Fees from midstream services	250.7	247.9	—	—	498.6
	595.0	3,380.4	4.9	—	3,980.3
Intersegment revenues					
Sales of commodities	1,425.5	157.2	—	(1,582.7)	—
Fees from midstream services	3.3	14.1	—	(17.4)	—
	1,428.8	171.3	—	(1,600.1)	—
Revenues	$2,023.8	$ 3,551.7	$4.9	$ (1,600.1)	$3,980.3
Operating margin	$351.1	$ 242.4	$4.9	$ (0.1)	$598.3
Other financial information:					
Total assets (1)	$10,845.2	$ 2,918.5	$46.7	$ 108.0	$13,918.4
Goodwill	$256.6	$ —	$—	$ —	$256.6
Capital expenditures	$434.7	$ 171.0	$—	$ 3.4	$609.1
Business acquisition	$987.1	$ —	$—	$ —	$987.1

(1) Corporate assets at the segment level primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	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, prepaids and debt issuance costs for our revolving credit facilities.

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,	
	2017	2016	2017	2016
Sales of commodities:				
Natural gas	$496.0	$309.5	$976.9	$636.4
NGL	1,034.3	923.5	2,349.0	1,708.9
Condensate	47.4	39.0	91.0	61.2
Petroleum products	40.1	22.3	59.9	31.8
Derivative activities	6.0	18.6	4.9	45.7
	1,623.8	1,312.9	3,481.7	2,484.0
Fees from midstream services:				
Fractionating and treating	32.0	31.5	63.0	61.6
Storage, terminaling, transportation and export	72.9	108.2	172.7	226.7
Gathering and processing	122.7	114.0	230.5	219.0
Other	16.3	17.0	32.4	34.7
	243.9	270.7	498.6	542.0
Total revenues	$1,867.7	$1,583.6	$3,980.3	$3,026.0

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,	
	2017	2016	2017	2016
Reconciliation of operating margin to net income (loss):				
Operating margin	$ 291.9	$ 299.5	$ 598.3	$ 598.8
Depreciation and amortization expenses	(203.4)	(186.1)	(394.6)	(379.6)
General and administrative expenses	(51.0)	(47.0)	(99.6)	(92.2)
Goodwill impairment	—	—	—	(24.0)
Interest expense, net	(62.1)	(71.4)	(125.1)	(124.3)
Other, net	(10.8)	(7.9)	(53.8)	10.9
Income tax (expense) benefit	106.0	(1.7)	34.9	(4.8)
Net income (loss)	$ 70.6	$ (14.6)	$ (39.9)	$ (15.2)

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, 2016 ("Annual Report"), as well as the unaudited consolidated financial statements and Notes hereto included in this Quarterly Report on Form 10-Q.

Overview

Targa Resources Corp. (NYSE: TRGP) is a publicly traded Delaware corporation formed in October 2005. Targa is a leading provider of midstream services and is one of the largest independent midstream energy companies in North America. We own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets.

On February 17, 2016, TRC completed its acquisition of all of the outstanding common units of Targa Resources Partners LP ("the Partnership" or "TRP") pursuant to the Agreement and Plan of Merger (the "TRC/TRP Merger Agreement" and such transaction, the "TRC/TRP Merger" or "Buy-in Transaction"). We issued 104,525,775 shares of common stock in exchange for all of the outstanding common units of the Partnership that we previously did not own, which were listed on the New York Stock Exchange ("NYSE") under the symbol "NGLS" prior to the consummation of the TRC/TRP Merger. As a result of the completion of the TRC/TRP Merger, the TRP common units are no longer publicly traded. The Partnership's 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") that were issued in October 2015 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 and no gain or loss was recognized in our Consolidated Statements of Operations related to the Buy-in Transaction. 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.

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: (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business).

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, fractionating, terminaling, transporting and marketing of NGLs and NGL products, including services to LPG exporters; storing and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses.

Logistics and Marketing operations are generally connected to and supplied in part by our Gathering and Processing segment 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 that are included in operating margin.

Recent Developments

Gathering and Processing Segment Expansion

Permian Acquisition

On March 1, 2017, we completed the purchase of 100% of the membership interests of Outrigger Delaware Operating, LLC, Outrigger Southern Delaware Operating, LLC (together “New Delaware”) and Outrigger Midland Operating, LLC (“New Midland” and together with New Delaware, the “Permian Acquisition”).

We paid $484.1 million in cash at closing on March 1, 2017, and paid an additional $90.0 million in cash on May 30, 2017 (collectively, the "initial purchase price"). Subject to certain performance-linked measures and other conditions, additional cash of up to $935.0 million may be payable to the sellers of New Delaware and New Midland in potential earn-out payments that may occur in 2018 and 2019. The potential earn-out payments will be based upon a multiple of realized gross margin from contracts that existed on March 1, 2017.

New Delaware's gas gathering and processing and crude gathering assets are located in Loving, Winkler, Pecos and Ward counties. The operations are backed by producer dedications of more than 145,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 14 years. The New Delaware assets include 70 MMcf/d of processing capacity and an uninstalled 60 MMcf/d plant, known as the Oahu Plant, which we are in the process of installing in the Delaware Basin with expectations of commencing operations in late 2017. Currently, there is 40,000 Bbl/d of crude gathering capacity on the New Delaware system.

New Midland's gas gathering and processing and crude gathering assets are located in Howard, Martin and Borden counties. The operations are backed by producer dedications of more than 105,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 13 years. The New Midland assets include 10 MMcf/d of processing capacity. Currently, there is 40,000 Bbl/d of crude gathering capacity on the New Midland system.

New Delaware's gas gathering and processing assets were connected to our Sand Hills system in the first quarter of 2017, and we expect that New Midland's gas gathering and processing assets will be connected to our existing WestTX system during 2017. We believe connecting the acquired assets to our legacy Permian footprint creates operational and capital synergies, and will afford enhanced flexibility in serving our producer customers.

Additional Permian System Processing Capacity

In November 2016, we announced plans to restart the idled 45 MMcf/d Benedum cryogenic processing plant and to add 20 MMcf/d of capacity at our Midkiff Plant in our WestTX system. The Benedum Plant was idled in September 2014 after the start-up of the 200 MMcf/d Edward Plant, and was brought back online in the first quarter of 2017. The addition of 20 MMcf/d of capacity at our Midkiff Plant was completed in the second quarter of 2017 and increased overall plant capacity of the Midkiff/Consolidator Plant complex in Reagan County, Texas from 210 MMcf/d to 230 MMcf/d. Also in November 2016, we announced plans to build the 200 MMcf/d Joyce Plant, which is expected to be completed in the first quarter of 2018. We expect total net growth capital expenditures for the Joyce Plant to be approximately $80 million.

In May 2017, we announced plans to build a new plant and expand the gathering footprint of our Permian Midland system in the Midland Basin. This project includes a new 200 MMcf/d cryogenic processing plant, known as the Johnson Plant, which is expected to begin operations in the third quarter of 2018. We expect total net growth capital expenditures for the Johnson Plant to be approximately $100 million.

Also in May 2017, we announced plans to build a new plant and expand the gathering footprint of our Permian Delaware system in the Delaware Basin. This project includes a new 250 MMcf/d cryogenic processing plant, known as the Wildcat Plant, which is expected to begin operations in the second quarter of 2018. We expect total net growth capital expenditures for the Wildcat Plant to be approximately $130 million.

Eagle Ford Shale Natural Gas Gathering and Processing Joint Ventures

In October 2015, we announced that we had entered into the Carnero Joint Ventures with Sanchez Energy Corporation (“Sanchez”) to construct the 200 MMcf/d Raptor Plant and approximately 45 miles of associated pipelines. In July 2016, Sanchez sold its interest in the gathering joint venture to Sanchez Midstream Partners, L.P. (“SNMP”), formerly known as Sanchez Production Partners, L.P., and in November 2016, sold its interest in the processing joint venture to SNMP. Through the Carnero Joint Ventures, we indirectly own a 50% interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect SNMP's Catarina gathering system to the plant. We hold the capacity on the high pressure gathering pipelines, and pay the gathering joint venture fees for transportation.

The Raptor Plant began operations in the second quarter of 2017, and is capable of processing 200 MMcf/d. In February 2017, we announced the addition of compression to increase the processing capacity of the Raptor Plant to 260 MMcf/d, which we expect to be completed in the third quarter of 2017. The Raptor Plant accommodates 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 pipelines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We manage operations of the high pressure gathering lines and the plant. Prior to the plant being placed in service, we benefited from Sanchez natural gas volumes that were processed at our Silver Oak facilities in Bee County, Texas.

Eagle Ford Shale Acquisition of Flag City Natural Gas Processing Plant

In May 2017, we acquired a 150 MMcf/d natural gas processing plant (the “Flag City Plant”) and associated assets from subsidiaries of Boardwalk Pipeline Partners, L.P. (“Boardwalk”) for $60 million, subject to customary closing adjustments. The gas processing activities under the Flag City Plant contracts have been transferred to our Silver Oak facilities. We shut down the Flag City Plant and are moving the plant and its component parts to other Targa locations.

Badlands

During 2017, we expect to invest approximately $150 million to expand our crude gathering and natural gas processing business in the Williston Basin, North Dakota. The expansion includes the addition of pipelines, LACT units, compression and other infrastructure to support continued growth in producer activity.

Sale of Venice Gathering System, L.L.C.

Through our 76.8% ownership interest in Venice Energy Services Company, L.L.C. (“VESCO”), we have operated the Venice Gas Plant and the Venice gathering system. On April 4, 2017, VESCO entered into a purchase and sale agreement with Rosefield Pipeline Company, LLC, an affiliate of Arena Energy, LP, to sell its 100% ownership interests in Venice Gathering System, L.L.C. (“VGS”), a Delaware limited liability company engaged in the business of transporting natural gas in interstate commerce, under authorization granted by and subject to the jurisdiction of the Federal Energy Regulatory Commission (“FERC”), for approximately $0.4 million in cash. Additionally, the VGS asset retirement obligations were assumed by the buyer. VGS owns and operates a natural gas gathering system in the Gulf of Mexico. Historically, VGS has been reported in our Gas Gathering and Processing segment. After the sale of VGS, we continue to operate the Venice Gas Plant through our ownership in VESCO. Targa Midstream Services LLC will continue to operate the Venice gathering system for up to four months after closing pursuant to a Transition Services Agreement with VGS.

Downstream Segment Expansion

Grand Prix NGL Pipeline

On May 25, 2017, we announced plans to construct a new common carrier NGL pipeline (“Grand Prix”), which will transport volumes from the Permian Basin and from our North Texas system to our fractionation and storage complex in the NGL market hub at Mont Belvieu. Grand Prix will be supported by our plant volumes and other third party customer commitments, and is expected to be in service in the second quarter of 2019. The initial capacity of the pipeline from the Permian Basin will be approximately 300 MBbl/d and will be expandable to 550 MBbl/d with the addition of pump stations. We expect total net growth capital expenditures for Grand Prix to be approximately $1.3 billion, with approximately $330 million of spending in 2017.

Financing Activities

On January 26, 2017, we completed a public offering of 9,200,000 shares of common stock (including underwriters' overallotment option) at a price to the public of $57.65, providing net proceeds after underwriting discounts, commissions and other expenses of $524.2 million. We used the net proceeds from this public offering to fund the cash portion of the Permian Acquisition purchase price due upon closing and for general corporate purposes.

On February 23, 2017, we amended the Partnership's account receivable securitization facility ("Securitization Facility") to increase the facility size to $350.0 million from $275.0 million.

On March 14, 2017, we used borrowings under our senior secured revolving credit facility ("TRC Revolver") to repay in full the $160.0 million outstanding balance on our senior secured term loan.

During the six months ended June 30, 2017, we sold 4,521,310 shares under the December 2016 EDA associated with our ATM program, resulting in net proceeds of $257.2 million.

In May 2017, the Partnership issued notice of full redemption to the trustee of its 6 % Senior Notes due August 2022 ("6 % Senior Notes"). The redemption price was 103.188% of the principal amount. The $278.7 million principal amount outstanding was redeemed on June 26, 2017 for a total redemption payment of $287.6 million, excluding accrued interest.

On May 9, 2017, we entered into an equity distribution agreement under the May 2016 Shelf (the "May 2017 EDA"), pursuant to which we may sell through our sales agents, at our option, up to an aggregated amount of $750.0 million of our common stock. For the six months ended June 30, 2017, no shares of common stock have been issued under the May 2017 EDA.

On June 1, 2017, we completed a public offering of 17,000,000 shares of our common stock at a price to the public of $46.10, providing net proceeds after underwriting discounts, commissions and other expenses of $777.3 million. We used the net proceeds from this public offering to fund a portion of the capital expenditures related to the construction of Grand Prix, repay outstanding borrowings under the our credit facilities, redeem the Partnership's 6 % Senior Notes, and for general corporate purposes.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see "Recent Accounting Pronouncements" included within Note 3 – Significant Accounting Policies in our Consolidated Financial Statements.

How We Evaluate Our Operations

The profitability of our business segments is a function of the difference between: (i) the revenues we receive from our 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 our 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 its 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 mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015; non-cash compensation on equity grants; transaction costs related to business acquisitions; the Splitter Agreement adjustment; 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 expense. 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 TRC. 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 its decision-making processes.

Distributable Cash Flow

We define distributable cash flow as Adjusted EBITDA less distributions to TRP preferred limited partners, the Splitter Agreement adjustment, cash interest expense on debt obligations, cash tax (expense) benefit 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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:				
Net income (loss) attributable to TRC	$ 57.6	$ (23.2)	$ (61.7)	$ (25.9)
Net income (loss) attributable to noncontrolling interests	13.0	8.6	21.8	10.7
Net income (loss)	70.6	(14.6)	(39.9)	(15.2)
Depreciation and amortization expense	203.4	186.1	394.6	379.6
General and administrative expense	51.0	47.0	99.6	92.2
Goodwill impairment	—	—	—	24.0
Interest expense, net	62.1	71.4	125.1	124.3
Income tax expense (benefit)	(106.0)	1.7	(34.9)	4.8
(Gain) loss on sale or disposition of assets	0.1	—	16.2	0.9
(Gain) loss from financing activities	10.7	3.3	16.5	(21.4)
Other, net	—	4.6	21.1	9.6
Operating margin	291.9	299.5	598.3	598.8
Operating expenses	155.2	138.9	307.2	271.0
Gross margin	$ 447.1	$ 438.4	$ 905.5	$ 869.8

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ 57.6	$ (23.2)	$ (61.7)	$ (25.9)
Impact of TRC/TRP Merger on NCI	—	—	—	(3.8)
Income attributable to TRP preferred limited partners	2.8	2.8	5.6	5.6
Interest expense, net	62.1	71.4	125.1	124.3
Income tax expense (benefit)	(106.0)	1.7	(34.9)	4.8
Depreciation and amortization expense	203.4	186.1	394.6	379.6
Goodwill impairment	—	—	—	24.0
(Gain) loss on sale or disposition of assets	0.1	—	16.2	0.9
(Gain) loss from financing activities	10.7	3.3	16.5	(21.4)
(Earnings) loss from unconsolidated affiliates	4.2	4.4	16.8	9.2
Distributions from unconsolidated affiliates and preferred partner interests, net	6.2	3.0	10.4	8.8
Change in contingent consideration included in Other expense	(2.1)	—	1.2	—
Compensation on equity grants	10.7	7.2	21.5	15.2
Transaction costs related to business acquisitions	0.1	—	5.2	—
Splitter Agreement (1)	10.8	—	21.5	—
Risk management activities	1.6	6.6	5.2	12.6
Noncontrolling interests adjustments (2)	(4.3)	(6.2)	(8.6)	(12.1)
TRC Adjusted EBITDA	$ 257.9	$ 257.1	$ 534.6	$ 521.8
Distributions to TRP preferred limited partners	(2.8)	(2.8)	(5.6)	(5.6)
Splitter Agreement (1)	(10.8)	—	(21.5)	—
Interest expense on debt obligations (3)	(56.6)	(65.9)	(115.5)	(135.6)
Cash tax (expense) benefit (4)	31.4	—	46.7	—
Maintenance capital expenditures	(23.3)	(20.2)	(49.0)	(35.2)
Noncontrolling interests adjustments of maintenance capex	0.2	1.4	0.5	2.2
Distributable Cash Flow	$ 196.0	$ 169.6	$ 390.2	$ 347.6

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(1) In Adjusted EBITDA, the Splitter Agreement adjustment represents the recognition of the annual cash payment received under the condensate splitter agreement over the four quarters following receipt. In Distributable Cash Flow, the Splitter Agreement adjustment represents the amounts necessary to reflect the annual cash payment in the period received less the amount recognized in Adjusted EBITDA.

(2) Noncontrolling interest portion of depreciation and amortization expense.

(3) Excludes amortization of interest expense.

(4) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which is being recognized over the periods between the Q3 2016 recognition of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before Q4 2017, was received in Q2 2017. The remaining $20.9 million unamortized balance of the tax refund was therefore included in Distributable Cash Flow

in the second quarter of 2017. Also includes a refund of Texas margin tax paid in previous periods and received in 2017.

Consolidated Results of Operations

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

	Three Months Ended June 30, 2017	2016	2017 vs. 2016		Six Months Ended June 30, 2017	2016	2017 vs. 2016	
	(In millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 1,623.8	$ 1,312.9	$ 310.9	24 %	$ 3,481.7	$ 2,484.0	$ 997.7	40 %
Fees from midstream services	243.9	270.7	(26.8)	(10 %)	498.6	542.0	(43.4)	(8 %)
Total revenues	1,867.7	1,583.6	284.1	18 %	3,980.3	3,026.0	954.3	32 %
Product purchases	1,420.6	1,145.2	275.4	24 %	3,074.8	2,156.2	918.6	43 %
Gross margin (1)	447.1	438.4	8.7	2 %	905.5	869.8	35.7	4 %
Operating expenses	155.2	138.9	16.3	12 %	307.2	271.0	36.2	13 %
Operating margin (1)	291.9	299.5	(7.6)	(3 %)	598.3	598.8	(0.5)	—
Depreciation and amortization expense	203.4	186.1	17.3	9 %	394.6	379.6	15.0	4 %
General and administrative expense	51.0	47.0	4.0	9 %	99.6	92.2	7.4	8 %
Goodwill impairment	—	—	—	—	—	24.0	(24.0)	(100%)
Other operating (income) expense	0.3	0.1	0.2	200%	16.5	1.1	15.4	NM
Income from operations	37.2	66.3	(29.1)	(44 %)	87.6	101.9	(14.3)	(14 %)
Interest expense, net	(62.1)	(71.4)	9.3	13 %	(125.1)	(124.3)	(0.8)	1 %
Equity earnings (loss)	(4.2)	(4.4)	0.2	5 %	(16.8)	(9.2)	(7.6)	83 %
Gain (loss) from financing activities	(10.7)	(3.3)	(7.4)	224%	(16.5)	21.4	(37.9)	(177%)
Other income (expense), net	4.4	(0.1)	4.5	NM	(4.0)	(0.2)	(3.8)	NM
Income tax (expense) benefit	106.0	(1.7)	107.7	NM	34.9	(4.8)	39.7	NM
Net income (loss)	70.6	(14.6)	85.2	NM	(39.9)	(15.2)	(24.7)	163 %
Less: Net income attributable to noncontrolling interests	13.0	8.6	4.4	51 %	21.8	10.7	11.1	104 %
Net income (loss) attributable to Targa Resources Corp.	57.6	(23.2)	80.8	NM	(61.7)	(25.9)	(35.8)	138 %
Dividends on Series A preferred stock	22.9	22.9	—	—	45.8	26.7	19.1	72 %
Deemed dividends on Series A preferred stock	6.3	6.5	(0.2)	(3 %)	12.5	6.5	6.0	92 %
Net income (loss) attributable to common shareholders	$ 28.4	$ (52.6)	$ 81.0	154%	$ (120.0)	$ (59.1)	$ (60.9)	103 %
Financial and operating data:								
Financial data:								
Adjusted EBITDA (1)	$ 257.9	$ 257.1	$ 0.8	—	$ 534.6	$ 521.8	$ 12.8	2 %
Distributable cash flow (1)	196.0	169.6	26.4	16 %	390.2	347.6	42.6	12 %
Capital expenditures	434.5	114.9	319.6	278%	609.1	291.8	317.3	109 %

Business acquisition (2)	—	—	—	—	987.1	—	987.1	—
Operating statistics: (3)								
Crude oil gathered, Badlands, MBbl/d	112.5	105.2	7.3	7 %	113.0	106.6	6.4	6 %
Crude oil gathered, Permian, MBbl/d (4)	28.6	—	28.6	—	18.9	—	18.9	—
Plant natural gas inlet, MMcf/d (5) (6)	3,391.2	3,511.4	(120.2)	(3 %)	3,304.6	3,452.1	(147.5)	(4 %)
Gross NGL production, MBbl/d	321.2	321.0	0.2	—	305.0	302.8	2.2	1 %
Export volumes, MBbl/d (7)	155.3	181.3	(26.0)	(14 %)	186.2	181.2	5.0	3 %
Natural gas sales, BBtu/d (6) (8)	1,957.3	1,958.4	(1.1)	—	1,885.7	1,966.5	(80.8)	(4 %)
NGL sales, MBbl/d (8)	473.9	516.8	(42.9)	(8 %)	503.6	532.3	(28.7)	(5 %)
Condensate sales, MBbl/d	12.1	11.4	0.7	6 %	11.5	10.4	1.1	11 %

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(1) Gross margin, operating margin, adjusted EBITDA, and distributable cash flow are non-GAAP financial measures and are discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."
(2) Includes the preliminary acquisition date fair value of the potential earn-out payments of $416.3 million due in 2018 and 2019.
(3) 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.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the quarter.
(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) 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.
(8) Includes the impact of intersegment eliminations.
NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

The increase in commodity sales was primarily due to higher commodity prices ($386.8 million) and higher petroleum products and condensate volumes ($13.7 million), partially offset by decreased NGL sales volumes ($77.0 million) and the impact of hedge settlements ($12.6 million). Fee-based and other revenues decreased primarily due to lower export fees and volumes, partially offset by higher crude gathering and gas processing fees.

The increase in product purchases was primarily due to the impact of higher commodity prices, partially offset by decreased volumes.

The higher gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating margin decreased as the increases in operating expenses more than offset the increases in gross margin. Operating expenses increased compared to 2016 due to higher fuel and power and higher maintenance in the Logistics and Marketing segment and the impact of the Permian Acquisition and other plant and system expansions in the Gathering and Processing segment. 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 expense reflects the impact of the Permian Acquisition and other growth investments, partially offset by the impact of fully depreciated property assets and lower scheduled amortization on the Badlands intangibles.

General and administrative expense increased primarily due to higher compensation and benefits, partially offset by lower professional services.

Net interest expense decreased primarily due to the impact of lower average outstanding borrowings during 2017.

During 2017, we recorded a loss from financing activities of $10.7 million on the redemption of the outstanding 6 % Senior Notes, whereas in 2016 we recorded a loss of $3.3 million on open debt market repurchases.

The income tax benefit for the three months ended June 30, 2017 is the result of the difference between the annual effective tax rate used to calculate income tax (expense) benefit for the three months ended March 31, 2017 and the statutory rate used to calculate income tax (expense) benefit for the six months ended June 30, 2017. For additional discussion of the basis for the calculation of the income tax benefit for the six months ended June 30, 2017, see the income tax explanation under the Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.

Net income attributable to noncontrolling interests was higher in 2017 due to increased earnings at our joint ventures as compared with 2016.

Preferred dividends represent both cash dividends related to the March 2016 Series A Preferred Stock offering and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The increase in commodity sales was primarily due to higher commodity prices ($1,148.6 million) and higher petroleum products and condensate volumes ($18.3 million), partially offset by decreased NGL and natural gas sales volumes ($131.1 million) and the impact of hedge settlements ($38.1 million). Fee-based and other revenues decreased primarily due to lower export fees.

The increase in product purchases was primarily due to the impact of higher commodity prices, partially offset by decreased volumes.

The higher gross margin in 2017 reflects increased segment margin results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment margins. Operating margin was relatively flat as compared to 2016 as the increases in gross margin were offset by the increases in operating expenses. Operating expenses increased compared to 2016 due to higher maintenance, higher fuel and power, and higher labor in the Logistics and Marketing segment and plant and system expansions. 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 expense reflects four months of operations from the Permian Acquisition in 2017 and the impact of other growth investments, primarily CBF Train 5 which went into service in the second quarter of 2016, partially offset by the impact of fully depreciated property assets and lower scheduled amortization on the Badlands intangibles.

General and administrative expense increased primarily due to higher compensation and benefits, partially offset by lower professional services.

We recognized an impairment of goodwill in the first quarter of 2016 of $24.0 million to finalize the 2015 provisional impairment of goodwill. The impairment charge related to goodwill acquired in the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively, the "Atlas mergers").

Other operating (income) expense in 2017 includes the loss due to the reduction in the carrying value of our ownership interest in the Venice Gathering System in connection with the April 4, 2017 sale.

Net interest expense in 2017 was flat as compared with 2016. Higher non-cash interest expense related to the mandatorily redeemable preferred interests liability that is revalued quarterly at the estimated redemption value as of the reporting date was offset by lower average outstanding borrowings during 2017.

Higher equity losses in 2017 reflects a $12.0 million loss provision due to the impairment of our investment in the T2 EF Cogen joint venture, partially offset by increased equity earnings at Gulf Coast Fractionators.

During 2017, we recorded a loss from financing activities of $16.5 million on the redemption of the outstanding 6 % Senior Notes and the repayment of the outstanding balance on our senior secured term loan, whereas in 2016 we recorded a gain of $21.4 million on open market debt repurchases.

We have historically calculated the provision for income taxes during interim reporting periods by applying an estimate of the annual effective tax rate for the full fiscal year to ordinary income or loss (pretax income or loss excluding unusual or infrequently occurring discrete items) for the reporting period. When calculating the annual estimated effective income tax rate for the six months ended June 30, 2017, we were subject to a loss limitation rule because the year-to-date ordinary loss exceeded the full-year expected ordinary loss. The tax benefit for that year-to-date ordinary loss was limited to the amount that would be recognized if the year-to-date ordinary loss were the anticipated ordinary loss for the full year. This requires us to use our statutory rate of 37.3% rather than the annual estimated effective tax rate to calculate the benefit for the period.

Net income attributable to noncontrolling interests was higher in 2017 due to the February 2016 TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for a portion of the first quarter 2016, and our October 2016 acquisition of the 37% interest of Versado that we did not already own. Further, earnings at our joint ventures increased as compared with 2016.

Preferred dividends represent both cash dividends related to the March 2016 Series A Preferred Stock offering and non-cash deemed dividends for the accretion of the preferred discount related to a beneficial conversion feature. Preferred dividends increased as the Series A Preferred Stock was outstanding for two full quarters in 2017, as compared to a portion of 2016.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	TRC Non-Partnership	Consolidated Operating Margin
	(In millions)				
Three Months Ended:					
June 30, 2017	$ 173.5	$ 112.4	$ 6.0	$ —	$ 291.9
June 30, 2016	139.1	141.8	18.6	—	299.5
Six Months Ended:					
June 30, 2017	$ 351.1	$ 242.4	$ 4.9	$ (0.1)	$ 598.3
June 30, 2016	254.7	298.5	45.7	(0.1)	598.8

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Gathering and Processing Segment

	Three Months Ended June 30,				Six Months Ended June 30,			
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
Gross margin	$ 264.2	$ 222.4	$ 41.8	19 %	$ 527.4	$ 416.5	$ 110.9	27 %
Operating expenses	90.7	83.3	7.4	9 %	176.3	161.8	14.5	9 %
Operating margin	$ 173.5	$ 139.1	$ 34.4	25 %	$ 351.1	$ 254.7	$ 96.4	38 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
SAOU (4)	311.6	259.2	52.4	20 %	293.7	251.3	42.4	17 %
WestTX	541.6	481.4	60.2	13 %	526.5	464.7	61.8	13 %
Total Permian Midland	853.2	740.6	112.6		820.2	716.0	104.2	
Sand Hills (4)	181.7	135.8	45.9	34 %	160.7	143.4	17.3	12 %
Versado	196.5	168.8	27.7	16 %	197.5	174.4	23.1	13 %
Total Permian Delaware	378.2	304.6	73.6		358.2	317.8	40.4	
Total Permian	1,231.4	1,045.2	186.2		1,178.4	1,033.8	144.6	
SouthTX	222.6	265.4	(42.8)	(16%)	197.4	220.5	(23.1)	(10%)
North Texas	277.1	327.5	(50.4)	(15%)	279.8	327.5	(47.7)	(15%)
SouthOK	479.0	470.7	8.3	2 %	459.8	464.3	(4.5)	(1 %)
WestOK	387.4	445.6	(58.2)	(13%)	390.3	466.3	(76.0)	(16%)
Total Central	1,366.1	1,509.2	(143.1)		1,327.3	1,478.6	(151.3)	
Badlands (5)	52.2	51.2	1.0	2 %	49.1	52.5	(3.4)	(6 %)
Total Field	2,649.7	2,605.6	44.1		2,554.8	2,564.9	(10.1)	
Coastal	741.6	905.8	(164.2)	(18%)	749.9	887.2	(137.3)	(15%)
Total	3,391.3	3,511.4	(120.1)	(3 %)	3,304.7	3,452.1	(147.4)	(4 %)
Gross NGL production, MBbl/d (3)								
SAOU (4)	37.9	32.2	5.7	18 %	35.6	30.7	4.9	16 %
WestTX	74.9	61.9	13.0	21 %	70.7	57.2	13.5	24 %
Total Permian Midland	112.8	94.1	18.7		106.3	87.9	18.4	
Sand Hills (4)	20.0	14.1	5.9	42 %	17.4	14.9	2.5	17 %
Versado	22.9	20.2	2.7	13 %	23.0	21.1	1.9	9 %
Total Permian Delaware	42.9	34.3	8.6		40.4	36.0	4.4	
Total Permian	155.7	128.4	27.3		146.7	123.9	22.8	
SouthTX	23.5	31.4	(7.9)	(25%)	20.1	27.3	(7.2)	(26%)
North Texas	31.1	37.0	(5.9)	(16%)	31.5	36.3	(4.8)	(13%)
SouthOK	38.5	47.3	(8.8)	(19%)	39.7	37.6	2.1	6 %
WestOK	23.5	29.7	(6.2)	(21%)	23.1	28.3	(5.2)	(18%)
Total Central	116.6	145.4	(28.8)		114.4	129.5	(15.1)	

Badlands	7.7	7.0	0.7	10 %	6.6	7.3	(0.7)	(10%)
Total Field	280.0	280.8	(0.8)		267.7	260.7	7.0	
Coastal	41.2	40.1	1.1	3 %	37.3	42.2	(4.9)	(12%)
Total	321.2	320.9	0.3	—	305.0	302.9	2.1	1 %
Crude oil gathered, Badlands, MBbl/d	112.5	105.2	7.3	7 %	113.0	106.6	6.4	6 %
Crude oil gathered, Permian, MBbl/d (4)	28.6	—	28.6	—	18.9	—	18.9	—
Natural gas sales, BBtu/d (3)	1,655.2	1,605.8	49.6	3 %	1,601.6	1,646.5	(44.9)	(3 %)
NGL sales, MBbl/d	249.2	256.1	(6.9)	(3 %)	238.4	237.7	0.7	—
Condensate sales, MBbl/d	12.1	10.9	1.3	12 %	11.4	10.2	1.3	13 %
Average realized prices (6):								
Natural gas, $/MMBtu	2.70	1.64	1.06	65 %	2.79	1.70	1.09	64 %
NGL, $/gal	0.46	0.36	0.10	28 %	0.48	0.32	0.16	50 %
Condensate, $/Bbl	42.74	37.94	4.81	13 %	43.79	32.21	11.58	36 %

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(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(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, other than Badlands.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales and NGL sales exclude producer take-in-kind volumes.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within SAOU and New Delaware volumes are included within Sand Hills. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the quarter.
(5) Badlands natural gas inlet represents the total wellhead gathered volume.
(6) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes, including those associated with the Permian Acquisition in 2017. Inlet volumes for Field Gathering and Processing were higher primarily due to increases at WestTX, SAOU, Sand Hills and Versado, partially offset by decreases at the other areas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower margins, more than offset the Field Gathering and Processing inlet volume increase. Higher NGL production in the Permian region was more than offset by lower NGL production in the other areas. Natural gas sales increased primarily due to increased Field Gathering and Processing inlet volumes. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. Total Badlands crude oil gathered volumes and natural gas volumes increased primarily due to system expansions.

The increase in operating expenses was primarily driven by the inclusion of the Permian Acquisition, plant and system expansions in the Permian region and the June 2017 commencement in operations of the Raptor Plant at SouthTX.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes, including those associated with the Permian Acquisition in 2017. Field Gathering and Processing inlet volume increases in the Permian region, specifically at WestTX, SAOU, Versado and Sand Hills, were offset by decreases at the other areas. The inlet volume decrease for Coastal Gathering and Processing, which generates significantly lower margins than does Field Gathering and Processing, accounted for over 93% of the overall inlet volume decrease. Despite overall lower inlet volumes, NGL production and NGL sales increased slightly primarily due to increased plant recoveries including additional ethane recovery. Natural gas sales decreased due to lower inlet volumes and increased ethane recovery. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. Total crude oil gathered in the Badlands increased due to system expansions. Badlands natural gas volumes decreased primarily due to the impact of the severe winter weather in the first quarter of 2017.

The increase in operating expenses was primarily driven by plant and system expansions in the Permian region, the inclusion of the Permian Acquisition and the June 2017 commencement in operations of the Raptor Plant at SouthTX.

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 Field portion of the Gathering and Processing segment:

Operating statistics:	Three Months Ended June 30, 2017			
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
SAOU (4)	311.6	100 %	311.6	311.6
WestTX (5) (6)	743.9	73 %	541.6	541.6
Total Permian Midland	1,055.5		853.2	853.2
Sand Hills (4)	181.7	100 %	181.7	181.7
Versado (7)	196.5	100 %	196.5	196.5
Total Permian Delaware	378.2		378.2	378.2
Total Permian	1,433.7		1,231.4	1,231.4
SouthTX	222.6	Varies (8) (9)	199.1	222.6
North Texas	277.1	100 %	277.1	277.1
SouthOK	479.0	Varies (10)	382.6	479.0
WestOK	387.4	100 %	387.4	387.4
Total Central	1,366.1		1,246.2	1,366.1
Badlands (11)	52.2	100 %	52.2	52.2
Total Field	2,852.0		2,529.8	2,649.7
Gross NGL production, MBbl/d (2)				
SAOU (4)	37.9	100 %	37.9	37.9
WestTX (5) (6)	102.9	73 %	74.9	74.9
Total Permian Midland	140.8		112.8	112.8
Sand Hills (4)	20.0	100 %	20.0	20.0
Versado (7)	22.9	100 %	22.9	22.9
Total Permian Delaware	42.9		42.9	42.9
Total Permian	183.7		155.7	155.7
SouthTX	23.5	Varies (8) (9)	20.8	23.5
North Texas	31.1	100 %	31.1	31.1
SouthOK	38.5	Varies (10)	31.4	38.5
WestOK	23.5	100 %	23.5	23.5
Total Central	116.6		106.8	116.6
Badlands	7.7	100 %	7.7	7.7
Total Field	308.0		270.2	280.0

(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 operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within SAOU and New Delaware volumes are included within Sand Hills.

(5) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.

(6) Includes the Buffalo Plant that commenced commercial operations in April 2016.

(7) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials. We held a 63% interest in Versado until October 31, 2016, when we acquired the remaining 37% interest.

(8) SouthTX includes the Silver Oak II Plant, of which we owned a 90% interest from October 2015 through May 2017, and after which we own a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(9) SouthTX also includes the Raptor Plant, which began operations in the second quarter of 2017, of which we own a 50% interest through the Carnero Processing Joint Venture. The Carnero Processing Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(10) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants which are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

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

	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	259.2	100	%	259.2	259.2
WestTX (4)	661.2	73	%	481.4	481.4
Total Permian Midland	920.4			740.6	740.6
Sand Hills	135.8	100	%	135.8	135.8
Versado (5)	168.8	63	%	106.3	168.8
Total Permian Delaware	304.6			242.1	304.6
Total Permian	1,225.0			982.7	1,045.2
SouthTX	265.4	Varies (6)		251.9	265.4
North Texas	327.5	100	%	327.5	327.5
SouthOK	470.7	Varies (7)		393.7	470.7
WestOK	445.6	100	%	445.6	445.6
Total Central	1,509.2			1,418.7	1,509.2
Badlands (8)	51.2	100	%	51.2	51.2
Total Field	2,785.4			2,452.6	2,605.6
Gross NGL production, MBbl/d (2)					
SAOU	32.2	100	%	32.2	32.2
WestTX (4)	85.0	73	%	61.9	61.9
Total Permian Midland	117.2			94.1	94.1
Sand Hills	14.1	100	%	14.1	14.1
Versado (5)	20.2	63	%	12.7	20.2
Total Permian Delaware	34.3			26.8	34.3
Total Permian	151.5			120.9	128.4
SouthTX	31.4	Varies (6)		30.2	31.4
North Texas	37.0	100	%	37.0	37.0
SouthOK	47.3	Varies (7)		44.0	47.3
WestOK	29.7	100	%	29.7	29.7
Total Central	145.4			140.9	145.4
Badlands	7.0	100	%	7.0	7.0
Total Field	303.9			268.8	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) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.

(5) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials. We held a 63% interest in Versado until October 31, 2016, when we acquired the remaining 37% interest.

(6) SouthTX includes the Silver Oak II Plant, of which we owned a 90% interest from October 2015 through May 2017, and after which we own a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(7) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants which are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

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

Logistics and Marketing Segment

	Three Months Ended June 30,				Six Months Ended June 30,			
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
	(In millions)							
Gross margin	$ 176.9	$ 197.6	$ (20.7)	(10%)	$ 373.2	$ 407.9	$ (34.7)	(9 %)
Operating expenses	64.5	55.8	8.7	16 %	130.8	109.4	21.4	20 %
Operating margin	$ 112.4	$ 141.8	$ (29.4)	(21%)	$ 242.4	$ 298.5	$ (56.1)	(19%)
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	338.5	329.8	8.7	3 %	321.8	312.7	9.1	3 %
LSNG treating volumes (2)	33.3	23.1	10.2	44 %	33.9	22.0	11.9	54 %
Benzene treating volumes (2)	22.1	23.1	(1.0)	(4 %)	22.8	22.0	0.8	4 %
Export volumes, MBbl/d (4)	155.3	181.3	(26.0)	(14%)	186.2	181.2	5.0	3 %
NGL sales, MBbl/d	439.4	463.6	(24.2)	(5 %)	470.5	472.8	(2.3)	—
Average realized prices:								
NGL realized price, $/gal	$ 0.58	$ 0.48	$ 0.10	21 %	$ 0.62	$ 0.44	$ 0.18	41 %

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter.
(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, 2017 Compared to Three Months Ended June 30, 2016

Logistics and Marketing gross margin decreased due to lower LPG export margin partially offset by higher fractionation margin, higher terminaling and storage throughput, and higher treating margin. LPG export margin decreased due to lower fees and volumes. Fractionation margin increased due to higher fees, an increase in system product gains and higher supply volume. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above). Treating margin increased slightly due to higher volumes partially offset by lower fees.

Operating expenses increased primarily due to higher fuel and power, which are largely passed through, and higher labor primarily associated with Train 5.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

The six month gross margin results were impacted by the same factors as discussed above for the quarter except that LPG export volumes were higher.

Operating expenses increased primarily due to higher fuel and power, which are largely passed through, higher maintenance associated with unusual one-time events in the first quarter of 2017, and higher labor associated with Train 5.

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	2017 vs. 2016	2017	2016	2017 vs. 2016
	(In millions)					
Gross margin	$6.0	$18.6	$(12.6)	$4.9	$45.7	$(40.8)
Operating margin	$6.0	$18.6	$(12.6)	$4.9	$45.7	$(40.8)

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash flow hedges. 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 entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes in our Gathering and Processing Operations that result from percent of proceeds/liquids processing arrangements. Because we are essentially forward-selling a portion of our future 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, 2017			Three Months Ended June 30, 2016			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2017 vs. 2016
Natural gas (BBtu)	15.5	$ 0.16	$ 2.5	10.7	$ 1.27	$ 13.6	$ (11.1)
NGL (MMgal)	59.4	0.01	0.8	13.1	0.09	1.0	(0.2)
Crude oil (MBbl)	0.3	6.93	2.3	0.3	15.72	4.4	(2.1)
Non-hedge accounting (2)			0.4			(0.1)	0.5
Ineffectiveness (3)			-			(0.3)	0.3
			$ 6.0			$ 18.6	$ (12.6)

	Six Months Ended June 30, 2017			Six Months Ended June 30, 2016			
	(In millions, except volumetric data and price amounts)						
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	2017 vs. 2016
Natural gas (BBtu)	26.0	$ 0.09	$ 2.6	20.2	$ 1.33	$ 26.9	$ (24.3)
NGL (MMgal)	102.7	(0.01)	(1.1)	27.3	0.18	5.0	(6.1)
Crude oil (MBbl)	0.6	6.29	3.5	0.5	23.82	11.5	(8.0)
Non-hedge accounting (2)			(0.3)			2.6	(2.9)
Ineffectiveness (3)			0.2			(0.3)	0.5
			$ 4.9			$ 45.7	$ (40.8)

(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 Targa Pipeline Partners, L.P. (“TPL”) that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding TPL derivative contracts with a fair value of $102.1 million as of February 27, 2015 (the “acquisition date”), were novated to us and included in the acquisition date fair value of assets acquired. We received derivative settlements of $1.9 million and $4.9 million for the three and six months ended June 30, 2017 and $6.3 million and $15.1 million for the three and six months ended June 30, 2016, related to these novated contracts. From the acquisition date through June 30, 2017, we have received total derivative settlements of $99.5 million. The remainder of the novated contracts will settle by the end of 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

Liquidity and Capital Resources

As of June 30, 2017, we had $98.7 million of "Cash and cash equivalents," on our Consolidated Balance Sheet. We believe our cash position, remaining borrowing capacity on our credit facilities (discussed below in "Short-term Liquidity"), and our cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

After completion of the TRC/TRP Merger, our liquidity and capital resources have been managed on a consolidated basis. We have the ability to access the Partnership's liquidity, subject to the limitations set forth in the Partnership Agreement and any restrictions contained in the covenants of the Partnership's debt agreements, as well as the ability to contribute capital to the Partnership, subject to any restrictions contained in the covenants of our debt agreements.

On a consolidated basis, our ability to finance our operations, including funding capital expenditures and acquisitions, meeting our indebtedness obligations, refinancing our indebtedness and meeting our collateral requirements, and paying dividends declared by our board of directors 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 commodity prices, weather and ongoing efforts to manage operating costs and maintenance capital expenditures, as well as general economic, financial, competitive, legislative, regulatory and other factors.

Historically, dividends have been funded by the cash distributions we received from the Partnership. In connection with the TRC/TRP Merger, TRC acquired all of the outstanding TRP common units that TRC and its subsidiaries did not already own. As a result, we are entitled to the entirety of distributions made by the Partnership on its equity interests, other than those made to the TRP Preferred Unitholders. The actual amount we declare as dividends continues to depend on our consolidated financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects, compliance with our debt covenants and any other matters that our board of directors deems relevant.

The Partnership's debt agreements and obligations to its Preferred Unitholders may restrict or prohibit the payment of distributions if the Partnership is in default, threat of default, or arrears. In addition, so long as any shares of our Preferred Shares are outstanding, certain common stock distribution limitations exist. If the Partnership cannot make distributions to us, we may be limited in our ability, or unable, to pay dividends on our common stock.

On a consolidated basis, our main sources of liquidity and capital resources are internally generated cash flows from operations, borrowings under the TRC Revolver, the TRP Revolver, and the Securitization Facility, and access to debt and equity capital markets. For companies involved in hydrocarbon production, transportation and other oil and gas related services, the capital markets have experienced and may continue to experience volatility. Our exposure to adverse credit conditions includes our credit facilities, cash investments, hedging abilities, customer performance risks and counterparty performance risks.

Short-term Liquidity

Our short-term liquidity on a consolidated basis as of July 31, 2017, was:

	July 31, 2017 (In millions)		
			Consolidated
	TRC	TRP	Total
Cash on hand	$22.8	$150.1	$ 172.9
Total availability under the TRC Revolver	670.0	—	670.0
Total availability under the TRP Revolver	—	1,600.0	1,600.0
Total availability under the Securitization Facility	—	274.0	274.0
	692.8	2,024.1	2,716.9
Less: Outstanding borrowings under the TRC Revolver	(435.0)	—	(435.0)
Outstanding borrowings under the TRP Revolver	—	(150.0)	(150.0)
Outstanding borrowings under the Securitization Facility	—	(274.0)	(274.0)
Outstanding letters of credit under the TRP Revolver	—	(20.4)	(20.4)
Total liquidity	$257.8	$1,579.7	$ 1,837.5

Other potential capital resources associated with our existing arrangements include:

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

Our right to request an additional $500 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on October 7, 2020.

- We may elect to pay dividends to Series A Preferred shareholders 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.

A portion of our capital resources are 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 that are tied to commodity sales and purchases are relatively balanced, with receivables from NGL and natural gas customers being 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 $94.8 million from December 31, 2016 to June 30, 2017. The major items contributing to this decrease were the increased capital accruals driven primarily by the Permian activity and the reclassification of a portion of the Permian Acquisition contingent consideration to current, the collection of an income tax refund, and a decrease in our net commodity receivables due to lower commodity revenue and reduced commodity purchases, partially offset by an increase in inventory due to price increases, an increase in our current net risk management position due to changes in the forward prices of commodities, and higher cash balances. The increase of $225.1 million in current debt obligations was due to reclassification of the remaining 5% Notes due January 2018 to short term.

Based on our anticipated levels of operations and absent any disruptive events, we believe that our internally generated cash flow, borrowings available under the TRC Revolver, the TRP Revolver and the Securitization Facility and proceeds from debt and equity offerings 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.

Long-term Financing

Our long-term financing consists of common stock, common warrants, preferred stock and long-term debt obligations. On January 26, 2017, we completed a public offering of 9,200,000 shares of our common stock (including the shares sold pursuant to the underwriters' overallotment option) at a price to the public of $57.65, providing net proceeds of $524.2 million. We used the net proceeds from this public offering to fund the cash portion of the Permian Acquisition purchase price due upon closing and for general corporate purposes. On June 1, 2017, we completed a public offering of 17,000,000 shares of our common stock at a price to the public of $46.10, providing net proceeds after underwriting discounts, commissions and other expenses of $777.3 million. We used the net proceeds from this public offering to fund a portion of the capital expenditures related to the construction of Grand Prix, repay outstanding borrowings under the Company's credit facilities, redeem the Partnership's 6 % Senior Notes, and for general corporate purposes.

During 2017, under the December 2016 equity distribution agreement, we issued and sold through our sales agents 4,532,421 shares of common stock and received net proceeds of $257.2 million. As of July 30, 2017, we have $411.2 million remaining under our December 2016 equity distribution agreement and the full $750.0 million remaining under our May 2017 equity distribution agreement.

During 2016, 19,983,843 warrants were exercised and net settled for 11,336,856 shares of common stock. For the six months ended June 30, 2017, no detachable Warrants were exercised. As a result, Series A Warrants exercisable into a maximum of 67,392 shares of common stock and Series B Warrants exercisable into a maximum of 32,496 shares of common stock were outstanding as of June 30, 2017.

From time to time, we issue long-term debt securities, which we refer to as senior notes. Our senior notes issued to date, generally have similar terms other than interest rates, maturity dates and redemption premiums. As of June 30, 2017 and December 31, 2016, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $3,962.6 million and $4,641.8 million, respectively.

We consolidate the debt of the Partnership with that of our own; however, we do not have the contractual obligation to make interest or principal payments with respect to the debt of the Partnership. Our debt obligations do not restrict the ability of the Partnership to make distributions to us. Our Credit Agreement has restrictions and covenants that may limit our ability to pay dividends to our stockholders. See Note 10 – Debt Obligations for more information regarding our debt obligations.

The majority of our consolidated long-term debt is fixed rate borrowings; however, we have some exposure to the risk of changes in interest rates, primarily as a result of the variable rate borrowings under the TRC Revolver and the TRP Revolver. We may enter into interest rate hedges with the intent to mitigate the impact of changes in interest rates on cash flows. As of June 30, 2017, we do not have any interest rate hedges.

To date, we do not believe our and our subsidiaries' debt balances have adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt-related transactions, see Note 10 - Debt Obligations to our consolidated financial statements. For information about our interest rate risk, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

Compliance with Debt Covenants

As of June 30, 2017, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

The 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 our 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 our operating cash flows using the direct method as a supplement to the presentation in our consolidated financial statements:

	Six Months Ended June 30,		
	2017	2016	2017 vs. 2016
	(In millions)		
Cash flows from operating activities:			
Cash received from customers	$4,109.5	$2,978.5	$1,131.0
Cash received from (paid to) derivative counterparties	9.9	51.1	(41.2)
Cash distributions from equity investments (1)	4.0	—	4.0
Cash outlays for:			
Product purchases	3,186.8	2,096.8	1,090.0
Operating expenses	332.0	256.9	75.1
General and administrative expense	94.6	75.3	19.3
Interest paid, net of amounts capitalized (2)	109.2	142.2	(33.0)
Income taxes paid, net of refunds	(67.8)	1.1	(68.9)
Other cash (receipts) payments	4.1	(0.2)	4.3
Net cash provided by operating activities	$464.5	$457.5	$7.0

(1) Excludes $3.2 million and $3.9 million included in investing activities for the six months ended June 30, 2017 and 2016 related to distributions from GCF and the T2 Joint Ventures that exceeded cumulative equity earnings.
(2) Net of capitalized interest paid of $4.1 million and $6.3 million included in investing activities for the six months ended June 30, 2017 and 2016.

Higher commodity prices were the primary contributor to increased cash collections and payments for product purchases in 2017 compared to 2016. Cash received from derivative settlements was lower as commodity price spreads between the prices paid to counterparties and the fixed prices we received on those derivative contracts were lower in 2017 in comparison to 2016. Interest payments are lower this year largely due to lower average outstanding debt balances, offset by the timing of payments of interest on two new series of notes we issued in 2016. Cash payments for general and administrative expenses and operating expenses were higher, primarily due to increases in compensation and benefits, contractor and other professional services, coupled with higher utilities and higher maintenance. The tax refund from net operating loss carry back was received in the second quarter of 2017, contributing to the change in cash tax paid net of refunds. Other cash payments in 2017 were higher mainly due to transaction expenses associated with the Permian Acquisition in 2017.

Cash Flows from Investing Activities

Six Months Ended June 30,		
2017	2016	2017 vs. 2016
(In millions)		
$(1,108.6)	$(305.2)	$(803.4)

Cash used in investing activities increased in 2017 compared to 2016, primarily due to the $570.8 million outlay for the cash portion of the Permian Acquisition consideration. Capital expenditures increased $219.9 million during 2017 reflecting the spending for major growth projects during 2017 and the acquisition of the Flag City Plant.

Cash Flows from Financing Activities

	Six Months Ended June 30,	
	2017	2016
Source of Financing Activities, net	(In millions)	
Debt, including financing costs	$(462.6)	$(918.6)
Equity offerings, net of financing costs	1,558.5	1,131.0
Dividends and distributions	(408.6)	(346.4)
Other	(18.0)	12.4
Net cash provided by (used in) financing activities	$669.3	$(121.6)

In 2017, we realized a net source of cash from financing activities, primarily due to equity offerings, offset by a net reduction of debt outstanding and payment of dividends and distributions. We issued 9,200,000 shares of common stock in January 2017 and 17,000,000 shares of common stock in June 2017 through public offerings in addition to common stock offerings through our December 2016 equity distribution agreement. A portion of the proceeds from the equity issuances was used to repay outstanding borrowings under the TRP Revolver and to redeem TRP's 6 % Senior Notes.

In 2016, we incurred a net use of cash from financing activities, primarily due to a net reduction of debt outstanding and payment of dividends and distributions, partially offset by proceeds from our Series A Preferred and Warrants offering. With the proceeds from equity issuances we repurchased a portion of the Partnership's senior notes through open market repurchases generally at a discount to par value and repaid a portion of our senior secured credit facilities.

Common Dividends

The following table details the dividends on common stock declared and/or paid by us for the six months ended June 30, 2017:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock (per share

					amounts)
June 30, 2017	August 15, 2017	$ 198.6	$ 196.2	$ 2.4	$ 0.91000
March 31, 2017	May 16, 2017	182.8	180.3	2.5	0.91000
December 31, 2016	February 15, 2017	178.3	176.5	1.8	0.91000

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

Preferred Dividends

Our Series A Preferred has 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. We may elect to pay dividends in kind ("PIK") for any quarter through December 31, 2017. Under the PIK election, unpaid dividends would be added to the liquidation preference and a commensurate amount of warrants would be issued. We have not made an election to PIK through June 30, 2017.

Cash dividends of $45.8 million were paid to holders of the Series A Preferred during the six months ended June 30, 2017. As of June 30, 2017, cash dividends accrued for our Series A Preferred were $22.9 million, which will be paid on August 14, 2017.

Capital Requirements

Our capital requirements relate to capital expenditures, which are classified as expansion expenditures including business acquisitions and 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, 2017	2016
	(In millions)	
Capital expenditures:		
Consideration for business acquisition	$987.1	$—
Contingent consideration (1)	(416.3)	—
Business acquisition, net of cash acquired	570.8	—
Expansion	560.0	256.6
Maintenance	49.1	35.2
Gross capital expenditures	609.1	291.8
Transfers from materials and supplies inventory to property, plant and equipment	(1.5)	(0.9)
Decrease in capital project payables and accruals	(80.0)	16.8
Cash outlays for capital projects	527.6	307.7
Total	$1,098.4	$307.7

(1) See Note 4 – Acquisitions and Divestitures of the “Consolidated Financial Statements.” Represents the preliminary estimated fair value of contingent consideration at the acquisition date.

We currently estimate that we will invest at least $1,375 million in net growth capital expenditures (exclusive of outlays for business acquisitions) for announced projects in 2017. 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 increased for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, primarily due to the spending related to the Joyce Plant, the Johnson Plant, the Wildcat Plant, related Midland Basin and Delaware Basin gas and crude gathering infrastructure expansions, Grand Prix NGL pipeline and the Channelview Splitter, as well as the acquisition of Flag City Plant. The increase is partially offset by the impact of the substantial completion of the CBF Train 5 construction project in the second quarter of 2016. We continue to expect that 2017 net maintenance capital expenditures will be approximately $110.0 million. Our maintenance capital expenditures increased for 2017 as compared to 2016, primarily due to higher numbers of compressors reaching the end of their maintenance cycles in the six months ended June 30, 2017 versus the six months ended June 30, 2016 and increased well connects.

Off-Balance Sheet Arrangements

As of June 30, 2017, there were $38.4 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 and (ii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Item 3. Quantitative and Qualitative Disclosures About Market 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.

Risk Management

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas equity volumes, NGL equity volumes and condensate equity volumes and future commodity purchases and sales through 2019. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Commodity Price Risk

A significant portion of our revenues are derived from percent-of-proceeds contracts under which we receive a portion of the proceeds from the sale of natural gas and/or NGLs 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 our 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, 2017, we have hedged the commodity price associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing operations that result from our percent-of-proceeds processing arrangements and (ii) future commodity purchases and sales in our Logistics and Marketing segment 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), futures 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, which 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.

A majority of 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 commodity 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.

We also enter into commodity price hedging transactions using futures contracts on futures exchanges. Exchange traded futures are subject to exchange margin requirements, so we may have to increase our cash deposit due to a rise in natural gas and NGL prices. Unlike bilateral hedges, we are not subject to counterparty credit risks when using futures on futures exchanges.

Our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $5.4 million and $17.6 million, during the three months ended June 30, 2017 and 2016, and $(1.3) million and $38.9 million, during the six months ended June 30, 2017 and 2016, as a result of transactions accounted for as derivatives. We account for derivatives designated as hedges that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in other comprehensive income until the underlying hedged transactions settle. 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 risk management position has moved from a net liability position of $53.3 million at December 31, 2016 to a net asset position of $38.0 million at June 30, 2017. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position.

As of June 30, 2017, we had the following derivative instruments that will settle during the years shown below:

Natural GAS

Instrument Type	Index	Price $/MMBtu		MMBtu/d 2017	2018	2019	Fair Value (In millions)
Gathering & Processing							
Swap	IF-Waha	2.87		103,600	-	-	$ 2.5
Swap	IF-Waha	2.68		-	73,600	-	3.5
Swap	IF-Waha	2.77		-	-	45,383	4.8
				103,600	73,600	45,383	
Swap	IF-PB	2.64		25,900	-	-	(0.3)
Swap	IF-PB	2.50		-	25,900	-	0.2
Swap	IF-PB	2.42		-	-	15,000	(0.0)
				25,900	25,900	15,000	
Swap	IF-PEPL	2.6835		16,000	-	-	(0.1)
Swap	IF-PEPL	2.6835		-	16,000	-	0.7
Swap	IF-PEPL	2.6835		-	-	16,000	1.3
				16,000	16,000	16,000	
Swap	NG-NYMEX	3.99		9,783	-	-	1.6
		Put Price	Call Price				
Collar	IF-Waha	3.00	3.67	7,500	-	-	0.5
Collar	IF-Waha	3.25	4.20	-	1,849	-	0.3
				7,500	1,849	-	
		Put Price	Call Price				
Collar	IF-PB	2.80	3.50	15,400	-	-	0.6
Collar	IF-PB	3.00	3.65	-	7,637	-	1.5

			15,400	7,637	-	
Basis Swap	EP-PERMIAN	(0.1444)	4,891	-	-	0.2
Basis Swap	PEPL	(0.3308)	4,891	-	-	0.0
Gathering & Processing total			187,965	124,986	76,383	$ 17.3
Other (1)						
Swap	NG-NYMEX	(3.1680)	(455)	(173)	(247)	$ (0.0)
Basis Swap	Various	Various	111,957	3,226	-	(0.7)
Future	Various	3.2640	-	1,103	-	(0.0)
Other total			111,502	4,156	(247)	$ (0.7)
						$ 16.6

(1) Other includes derivative agreements entered into for the purpose of hedging future commodity purchases and sales in our Logistics and Marketing segment.

NGLs

Instrument Type	Index	Price $/gal		Bbl/d 2017	2018	2019	Fair Value (In millions)
Gathering & Processing							
Swap	C2-OPIS-MB	0.2781		4,830	-	-	$ 0.9
Swap	C2-OPIS-MB	0.2794		-	2,918	-	(0.1)
Swap	C2-OPIS-MB	0.2917		-	-	2,260	(0.8)
Total				4,830	2,918	2,260	
Swap	C3-OPIS-MB	0.6456		7,802	-	-	1.8
Swap	C3-OPIS-MB	0.5530		-	2,650	-	(0.4)
Swap	C3-OPIS-MB	0.5530		-	-	2,650	0.4
Total				7,802	2,650	2,650	
Swap	IC4-OPIS-MB	0.8065		740	-	-	0.3
Swap	IC4-OPIS-MB	0.7487		-	230	-	0.2
Swap	IC4-OPIS-MB	0.7200		-	-	110	0.1
Total				740	230	110	
Swap	NC4-OPIS-MB	0.7935		1,800	-	-	0.7
Swap	NC4-OPIS-MB	0.7388		-	600	-	0.6
Swap	NC4-OPIS-MB	0.7050		-	-	300	0.2
Total				1,800	600	300	
Swap	C5-OPIS-MB	1.1056		1,510	-	-	0.9
Swap	C5-OPIS-MB	1.0385		-	810	-	(0.1)
Swap	C5-OPIS-MB	1.0825		-	-	569	0.4
Total				1,510	810	569	
		Put Price	Call Price				
Collar	C2-OPIS-MB	0.240	0.290	410	-	-	0.0
Total				410	-	-	
		Put Price	Call Price				
Collar	C3-OPIS-MB	0.570	0.68625	380	-	-	0.0
Collar	C3-OPIS-MB	0.530	0.65000	-	900	-	0.1
Total				380	900	-	

		Put Price	Call Price				
Collar	IC4-OPIS-MB			-	-	-	0.0
Collar	IC4-OPIS-MB	0.650	0.840	-	110	-	0.0
Collar	IC4-OPIS-MB	0.640	0.800	-	-	110	0.1
Total				-	110	110	
		Put Price	Call Price				
Collar	NC4-OPIS-MB			-	-	-	0.0
Collar	NC4-OPIS-MB	0.650	0.800	-	300	-	0.1
Collar	NC4-OPIS-MB	0.640	0.760	-	-	300	0.1
Total				-	300	300	
		Put Price	Call Price				
Collar	C5-OPIS-MB	1.210	1.415	130	-	-	0.2
Collar	C5-OPIS-MB	1.230	1.385	-	32	-	0.1
Total				130	32	-	
Gathering & Processing total				17,602	8,550	6,299	$ 5.8
Other (1)(2)							
Future	C2-OPIS-MB	0.2741		5,707	-	-	$ 0.7
Future	C2-OPIS-MB	0.3007		-	1,534	-	0.4
Total				5,707	1,534	-	
Future	C3-OPIS-MB	0.6520		9,321	-	-	2.2

Future C3-OPIS-MB	0.6257	-	4,384	-	0.3
Total		9,321	4,384	-	
Future IC4-OPIS-MB	0.7728	679	-	-	0.1
Future IC4-OPIS-MB	0.7825	-	55	-	0.0
Total		679	55	-	
Future NC4-OPIS-MB	0.7652	2,690	-	-	0.4
Future NC4-OPIS-MB	0.8027	-	1,616	-	1.5
Total		2,690	1,616	-	
Future C5-OPIS-MB	0.9846	190	-	-	(0.1)
Future C5-OPIS-MB	1.0725	-	27	-	0.0
Total		190	27	-	
Put Price					
Option C2-OPIS-MB	0.2694	1,087	-	-	0.3
Option C2-OPIS-MB	0.2963	-	1,644	-	1.3
Total		1,087	1,644	-	
Other total		19,674	9,260	-	$ 7.1
					$ 12.9

(1) Other includes derivative agreements entered into for the purpose of hedging future commodity purchases and sales in our Logistics and Marketing segment.

(2) The “Future” line items are comprised of futures transactions entered into on both the Intercontinental Exchange (“ICE”) and Chicago Mercantile Exchange (“CME”).

CONDENSATE

Instrument Type	Index	Price $/Bbl		Bbl/d 2017	2018	2019	Fair Value (In millions)
Gathering & Processing							
Swap	WTI-NYMEX	54.54		2,690	-	-	$ 3.8
Swap	WTI-NYMEX	48.79		-	2,190	-	0.4
Swap	WTI-NYMEX	51.19		-	-	1,063	0.7
				2,690	2,190	1,063	
		Put Price	Call Price				
Collar	WTI-NYMEX	54.04	64.09	1,380	-	-	2.1

Collar	WTI-NYMEX	49.76	58.50	-	691	-	1.1
Collar	WTI-NYMEX	48.00	56.25	-	-	590	0.4
				1,380	691	590	
Total				4,070	2,881	1,653	
							$ 8.5

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 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 contract, the valuations are classified as Level 3 within the fair value hierarchy. See Note 17 - Fair Value Measurements in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRC Revolver, the TRP Revolver and the Securitization Facility. As of June 30, 2017, we do not have any interest rate hedges. However, we may enter into interest rate hedges in the future with the intent to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRC Revolver, TRP Revolver and the Securitization Facility will also increase. As of June 30, 2017, the Partnership had $250.0 million in outstanding variable rate borrowings under the TRP Revolver and Securitization Facility, and we had outstanding variable rate borrowings of $435.0 million under the TRC Revolver. 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 $2.5 million and our consolidated annual interest expense by $6.9 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 margined 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 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 $15.0 million as of June 30, 2017. The range of losses attributable to our individual counterparties would be between $0.4 million and $16.7 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 as of June 30, 2017, our operating income would decrease by $5.5 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 such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were not effective to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow for timely decisions regarding required disclosure because of the material weakness in our internal control over financial reporting as described below.

Previously Identified Material Weakness in Internal Control Over Financial Reporting

As previously disclosed in our Annual Report, we did not maintain effective controls over the preparation and review of income tax provisions for interim periods. Specifically, our controls were not designed to detect material clerical errors, as well as identify and address unusual and infrequently occurring circumstances requiring special consideration under accounting standards applicable to the determination of income tax expense for interim periods.

Remediation Status

In response to the material weakness disclosed in our Annual Report, we developed a plan for remediation that consists of the following elements:

- Performing an independent detailed review and re-performance of key elements of the interim tax provision calculation and entries to provide additional assurance that clerical errors are detected, and that detailed reviews already required under our controls and procedures are performed timely and effectively.
- Incorporating into our process a formal interim tax provision checklist designed to ensure that we identify and appropriately address unusual and infrequently occurring circumstances requiring special consideration under GAAP applicable to interim income taxes.
- Conducting formal reviews with financial and tax executive management to provide enhanced transparency and to facilitate an assessment of appropriateness of the estimated annual effective tax rate utilized in the preparation of interim income tax provisions.

We are in the process of testing and evaluating the operational effectiveness of the revised controls and procedures in conjunction with the preparation of our interim financial statements during 2017.

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting, during our most recent fiscal quarter.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings.

The information required for this item is provided in Note 18 – 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 Annual Report. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

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

Recent Sales of Unregistered Securities.

None.

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, 2017 - May 31, 2017	517	$ 55.44	—	—
June 1, 2017 - June 30, 2017	35,351	$ 44.93	—	—

(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

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	Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, effective December 1, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 21, 2016 (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)).
10.1+	Amended and Restated Targa Resources Corp. 2010 Stock Incentive Plan, as amended and restated effective May 22, 2017 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed May 23, 2017 (File No. 001-34991)).
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
+Management contract or compensatory plan or arrangement

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, 2017 By: /s/ Matthew J. Meloy
Matthew J. Meloy
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)