Targa Resources Corp.
Form 10-Q
August 09, 2018

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, 2018

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.)
811 Louisiana St, Suite 2100, 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 August 6, 2018, there were 225,558,580 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, 2017 ("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, 2018 ("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
SCOOP	South Central Oklahoma Oil Province
STACK	Sooner Trend, Anadarko, Canadian and Kingfisher

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
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, 2018 (Unaudited)	December 31, 2017
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$281.6	$ 137.2
Trade receivables, net of allowances of $0.0 and $0.1 million at June 30, 2018 and December 31, 2017	867.2	827.6
Inventories	181.4	204.5
Assets from risk management activities	54.2	37.9
Other current assets	47.1	62.7
Total current assets	1,431.5	1,269.9
Property, plant and equipment	15,451.0	14,205.4
Accumulated depreciation	(4,029.7)	(3,775.4)
Property, plant and equipment, net	11,421.3	10,430.0
Intangible assets, net	2,074.3	2,165.8
Goodwill, net	256.6	256.6
Long-term assets from risk management activities	21.7	23.2
Investments in unconsolidated affiliates	363.9	221.6
Other long-term assets	26.8	21.5
Total assets	$15,596.1	$ 14,388.6
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$1,670.1	$ 1,186.9
Liabilities from risk management activities	103.2	79.7
Current debt obligations	180.0	350.0
Total current liabilities	1,953.3	1,616.6
Long-term debt	5,392.5	4,703.0
Long-term liabilities from risk management activities	35.5	19.6
Deferred income taxes, net	519.2	479.0
Other long-term liabilities	214.8	597.9
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 11)	230.6	216.5
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, 2018 — 226,127,081 / 225,487,048		
December 31, 2017 — 218,152,620 / 217,566,980		
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	6,233.7	6,302.8
Retained earnings (deficit)	60.0	(77.2)
Accumulated other comprehensive income (loss)	(37.9)	(29.9)
Treasury stock, at cost (640,033 shares as of June 30, 2018 and 585,640 shares as of December 31, 2017)	(38.2)	(35.6)
Total Targa Resources Corp. stockholders' equity	6,217.8	6,160.3
Noncontrolling interests in subsidiaries	1,032.4	595.7
Total owners' equity	7,250.2	6,756.0
Total liabilities, Series A Preferred Stock and owners' equity	$15,596.1	$ 14,388.6

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(Unaudited)			
	(In millions, except per share amounts)			
Revenues:				
Sales of commodities (see Note 3)	$2,154.1	$1,623.8	$4,327.4	$3,481.7
Fees from midstream services (see Note 3)	290.3	243.9	572.6	498.6
Total revenues	2,444.4	1,867.7	4,900.0	3,980.3
Costs and expenses:				
Product purchases (see Note 3)	1,905.3	1,420.6	3,846.2	3,074.8
Operating expenses	170.5	155.2	343.7	307.2
Depreciation and amortization expense	202.6	203.4	400.7	394.6
General and administrative expense	57.0	51.0	113.8	99.6
Other operating (income) expense	(46.4)	0.3	(46.1)	16.5
Income (loss) from operations	155.4	37.2	241.7	87.6
Other income (expense):				
Interest income (expense), net	(62.0)	(62.1)	(46.0)	(125.1)
Equity earnings (loss)	1.9	(4.2)	3.4	(16.8)
Gain (loss) from financing activities	(2.0)	(10.7)	(2.0)	(16.5)
Change in contingent considerations	60.6	2.1	4.5	(1.2)
Other, net	—	2.3	—	(2.8)
Income (loss) before income taxes	153.9	(35.4)	201.6	(74.8)
Income tax (expense) benefit	(32.8)	106.0	(41.6)	34.9
Net income (loss)	121.1	70.6	160.0	(39.9)
Less: Net income (loss) attributable to noncontrolling interests	12.0	13.0	28.0	21.8
Net income (loss) attributable to Targa Resources Corp.	109.1	57.6	132.0	(61.7)
Dividends on Series A Preferred Stock	22.9	22.9	45.8	45.8
Deemed dividends on Series A Preferred Stock	7.2	6.3	14.1	12.5
Net income (loss) attributable to common shareholders	$79.0	$28.4	$72.1	$(120.0)
Net income (loss) per common share - basic	$0.36	$0.14	$0.33	$(0.61)
Net income (loss) per common share - diluted	$0.35	$0.14	$0.33	$(0.61)
Weighted average shares outstanding - basic	221.1	203.7	219.9	197.8
Weighted average shares outstanding - diluted	222.8	205.0	221.5	197.8
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, 2018			2017		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income (loss)			$ 121.1			$ 70.6
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ (103.0)	$ 26.0	(77.0)	$ 29.8	$ (11.3)	18.5
Settlements reclassified to revenues	7.8	(3.2)	4.6	(5.7)	2.2	(3.5)
Other comprehensive income (loss)	(95.2)	22.8	(72.4)	24.1	(9.1)	15.0
Comprehensive income (loss)			48.7			85.6
Less: Comprehensive income (loss) attributable to noncontrolling interests			12.0			13.0
Comprehensive income (loss) attributable to Targa Resources Corp.			$ 36.7			$ 72.6

	Six Months Ended June 30, 2018			2017		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income (loss)			$ 160.0			$ (39.9)
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ (38.3)	$ 10.6	(27.7)	$ 96.0	$ (36.5)	59.5
Settlements reclassified to revenues	34.4	(9.5)	24.9	0.4	(0.1)	0.3
Other comprehensive income (loss)	(3.9)	1.1	(2.8)	96.4	(36.6)	59.8
Comprehensive income (loss)			157.2			19.9
Less: Comprehensive income (loss) attributable to noncontrolling interests			28.0			21.8
Comprehensive income (loss) attributable to Targa Resources Corp.			$ 129.2			$ (1.9)

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, 2017	217,567	$0.2	$6,302.8	$(77.2)	$(29.9)	586	$(35.6)	$595.7	$6,756.0	$216.5
Impact of accounting standard adoption (see Note 3)	—	—	—	5.2	(5.2)	—	—	—	—	—
Compensation on equity grants	—	—	26.9	—	—	—	—	—	26.9	—
Distribution equivalent rights	—	—	(6.5)	—	—	—	—	—	(6.5)	—
Shares issued under compensation program	235	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(54)	—	—	—	—	54	(2.6)	—	(2.6)	—
Issuance of common stock	7,680	—	369.5	—	—	—	—	—	369.5	—
Exercise of warrants - share settled	59	—	—	—	—	—	—	—	—	—
Series A Preferred Stock dividends										
Dividends	—	—	—	(45.8)	—	—	—	—	(45.8)	—
Dividends in excess of retained	—	—	(45.8)	45.8	—	—	—	—	—	—

earnings										
Deemed dividends - accretion of beneficial conversion feature	—	—	(14.1)	—	—	—	—	—	(14.1)	14.1
Common stock dividends										
Dividends	—	—	—	(399.1)	—	—	—	—	(399.1)	—
Dividends in excess of retained earnings	—	—	(399.1)	399.1	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(39.4)	(39.4)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	447.1	447.1	—
Acquisition of related party (see Note 17)	—	—	—	—	—	—	—	1.1	1.1	—
Purchase of noncontrolling interests in subsidiary	—	—	—	—	—	—	—	(0.1)	(0.1)	—
Other comprehensive income (loss)	—	—	—	—	(2.8)	—	—	—	(2.8)	—
Net income (loss)	—	—	—	132.0	—	—	—	28.0	160.0	—
Balance, June 30, 2018	225,487	$ 0.2	$ 6,233.7	$ 60.0	$ (37.9)	640	$ (38.2)	$ 1,032.4	$ 7,250.2	$ 230.6

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.

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

	Common Stock		Additional Paid in	Retained Earnings (Accumulated	Accumulated Other Comprehensive Income	Treasury Shares		Noncontrolling	Total Owner's	Series A Preferred
	Shares	Amount	Capital	Deficit)	(Loss)	Shares	Amount	Interests	Equity	Stock
	(Unaudited)									
	(In millions, except shares in thousands)									
Balance, December 31, 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	—	—	—	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 beneficial conversion	—	—	(12.5)	—	—	—	—	—	(12.5)	12.5

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

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2018	2017
	(Unaudited)	
	(In millions)	
Cash flows from operating activities		
Net income (loss)	$ 160.0	$ (39.9)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	5.6	5.9
Compensation on equity grants	26.9	21.5
Depreciation and amortization expense	400.7	394.6
Accretion of asset retirement obligations	1.9	2.2
Increase (decrease) in redemption value of mandatorily redeemable preferred interests	(75.4)	6.9
Deferred income tax expense (benefit)	41.6	(34.5)
Equity (earnings) loss of unconsolidated affiliates	(3.4)	16.8
Distributions of earnings received from unconsolidated affiliates	9.7	4.0
Risk management activities	10.4	5.2
(Gain) loss on sale or disposition of assets	(46.8)	16.2
(Gain) loss from financing activities	2.0	16.5
Change in contingent considerations included in Other expense (income)	(4.5)	1.2
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	(8.8)	303.8
Inventories	9.3	(68.6)
Accounts payable and other liabilities	14.5	(187.3)
Net cash provided by operating activities	543.7	464.5
Cash flows from investing activities		
Outlays for property, plant and equipment	(1,162.5)	(527.6)
Outlays for business acquisition, net of cash acquired	—	(570.8)
Proceeds from sale of assets	71.5	1.0
Investments in unconsolidated affiliates	(142.6)	(0.6)
Return of capital from unconsolidated affiliates	2.0	3.2
Other, net	(5.3)	(13.8)
Net cash used in investing activities	(1,236.9)	(1,108.6)
Cash flows from financing activities		
Debt obligations:		
Proceeds from borrowings under credit facilities	640.0	1,926.0
Repayments of credit facilities	(945.0)	(1,916.0)
Proceeds from borrowings under accounts receivable securitization facility	270.0	218.5
Repayments of accounts receivable securitization facility	(440.0)	(243.5)
Proceeds from issuance of senior notes and term loan	1,000.0	—
Redemption of senior notes and term loan	—	(447.6)
Proceeds from issuance of common stock	372.4	1,573.4
Costs incurred in connection with financing arrangements	(21.7)	(14.9)

Repurchase of shares and units under compensation plans	(0.4)	(0.6)
Purchase of noncontrolling interests in subsidiary	(0.1)	(12.5)
Contributions from noncontrolling interests	447.1	16.5
Distributions to noncontrolling interests	(33.8)	(21.4)
Distributions to Partnership unitholders	(5.6)	(5.6)
Dividends paid to common and Series A preferred shareholders	(445.3)	(403.0)
Net cash provided by (used in) financing activities	837.6	669.3
Net change in cash and cash equivalents	144.4	25.2
Cash and cash equivalents, beginning of period	137.2	73.5
Cash and cash equivalents, end of period	$281.6	$98.7

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, terminaling and selling crude oil; and
- storing, terminaling and selling refined petroleum products.

See Note 22 – 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, 2018 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, 2018 are not necessarily indicative of the results that may be expected for the full year.

Note 3 — Significant Accounting Policies

Recent Accounting Pronouncements

Recently issued accounting pronouncements not yet adopted

Leases

In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-02, Leases (Topic 842). The amendments in this update require, among other items, 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. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. We are currently monitoring recent exposure drafts and clarifications issued by the FASB.

In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. The amendments in this update permit an entity to elect an optional transition practical expedient to not evaluate land easements that existed or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.

In July 2018, the FASB issued ASU 2018-10, Codification Improvements to Topic 842, Leases. The amendments in this update affect narrow aspects of the guidance issued in ASU 2016-02 and is intended to alleviate unintended consequences from applying the new standard. The amendments do not make substantive changes to the core provisions or principles of the new standard and will be considered during our implementation process.

In July 2018, the FASB also issued ASU 2018-11, Leases (Topic 842): Targeted Improvements. The amendments in this update provide entities with an optional transition method, which permits an entity to initially apply the new leases standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. In addition, the amendments in this update also provide lessors with a practical expedient (provided certain conditions are met), by class of underlying asset, to not separate the nonlease component(s) from the associated lease component for purposes of income statement presentation.

We expect to adopt Topic 842 on January 1, 2019, and intend to elect the land easement practical expedient as well as the optional additional transition method. We are currently in the process of gathering a complete population of our lease arrangements, securing a software solution, and evaluating the impact of the new standard on our consolidated financial statements. Based on our evaluation to-date and from the perspective as the lessee, our leasing activity primarily consists of railcars, office space, tractors, vehicles and terminals. Though the evaluation process is still in progress, we currently anticipate that this new lease guidance will result in changes to the way we recognize, present and disclose our operating leases in our consolidated financial statements, including the recognition of a lease liability and an offsetting right-of-use asset in our consolidated balance sheet for our operating leases (with the exception of short-term 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. The amendments in this update 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 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 also 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. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2019, with early adoption permitted. We expect to early adopt the amendments on January 1, 2019 and do not expect a material impact on our consolidated financial statements.

Recently adopted accounting pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). The amendments in this update supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The amendments also create 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 core principal of Topic 606 is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to, in exchange for those goods or services. We adopted Topic 606 on January 1, 2018 by applying the modified retrospective transition approach to contracts which were not completed as of the date of adoption. The adoption of Topic 606 did not result in a material cumulative effect adjustment to retained earnings on January 1, 2018. However, the adoption did have an impact on the classification between "Fees from midstream services" and "Product purchases," as well as the reporting of gross vs. net revenues, as discussed below:

- Embedded fees within commodity supply contracts where the counterparty is not deemed to be a customer are now reported as a reduction of "Product purchases." Historically, such fees were reported as "Fees from midstream services."
- Noncash consideration in the form of commodities received in-kind from a customer is now recognized as service revenue within "Fees from midstream services" when the service is performed. Historically, the noncash consideration was only recognized as revenue upon sale to a third party without corresponding "Product purchases."
- For certain contracts structured as a purchase where we do not control the commodities, but rather are acting as an agent for the supplier, revenue is now recognized for the net amount of consideration we expect to retain in exchange for our service. Historically, the purchase from the supplier and subsequent sale were reported gross.

The following tables summarize the effects of adoption on our consolidated financial statements:

	Three Months Ended June 30, 2018		
	Pre-Adoption	Effect of Adoption	Post-Adoption
Revenues:			
Sales of commodities	$2,234.0	$ (79.9)	$ 2,154.1
Fees from midstream services	296.5	(6.2)	290.3
Total revenues	2,530.5	(86.1)	2,444.4
Costs and expenses:			
Product purchases	1,991.4	(86.1)	1,905.3
Income from operations	155.4	—	155.4
Income (loss) before income taxes	153.9	—	153.9
Net income (loss)	$121.1	$ —	$ 121.1

	Six Months Ended June 30, 2018		
	Pre-Adoption	Effect of Adoption	Post-Adoption
Revenues:			

Sales of commodities	$4,493.4	$ (166.0)	$ 4,327.4
Fees from midstream services	585.4	(12.8)	572.6
Total revenues	5,078.8	(178.8)	4,900.0
Costs and expenses:			
Product purchases	4,025.0	(178.8)	3,846.2
Income from operations	241.7	—	241.7
Income (loss) before income taxes	201.6	—	201.6
Net income (loss)	$160.0	$ —	$ 160.0

See Note 19 – Revenue for information regarding our performance obligations and Note 22 – Segment Information for further disaggregation of our revenues.

Targeted Improvements to Accounting for Hedge Activities

In August 2017, FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedge Activities. The amendments in this update are intended to better align risk management activities and financial reporting for hedging relationships. The amendments cover multiple aspects of hedge accounting including: (1) change the way in which ineffectiveness is accounted; (2) allow for new hedge strategies; and (3) change hedge disclosures. Under the new guidance, companies will have the option to perform a qualitative quarterly effectiveness assessment once the initial quantitative test has been performed. In addition, any ineffectiveness that exists is required to be recorded in other comprehensive income instead of in earnings as was required under prior guidance. Several new hedging strategies qualify for hedge accounting treatment, most of these strategies involving the hedging of contractually specified components. Lastly, disclosure requirements have been updated to: (1) require that hedge income be presented on the same line item as the related hedged item; (2) require hedge program objectives to be disclosed; and (3) eliminate the requirement to separately disclose ineffectiveness. These amendments are effective for fiscal years beginning after December 15, 2018, and interim periods within those years, with early adoption permitted. We early adopted the amendments on January 1, 2018, with the changes to ineffectiveness resulting in no effect on retained earnings, as we had no accumulated ineffectiveness at December 31, 2017. See updated disclosures as a result of these amendments in Note 15 – Derivative Instruments and Hedging Activities and Note 22 – Segment Information.

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). The amendments in this update clarify how entities should classify certain cash receipts and cash payments in 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. The amendments were effective for us on January 1, 2018 and were adopted on a retrospective basis, with no material effect on our consolidated financial statements. In addition, we elected to continue to apply our historical cumulative earnings approach to classify distributions received from equity method investees.

Other Income

In February 2017, FASB issued ASU 2017-05, Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20). The amendments in this update clarify the scope of Subtopic 610-20 and add guidance for partial sales of nonfinancial assets. Subtopic 610-20 was issued in May 2014 as part of ASU 2014-09, Revenue from Contracts with Customers (Topic 606), and provides guidance for recognizing gains and losses from the transfer of nonfinancial assets in contracts with noncustomers. 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 nonfinancial 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 were effective for us on January 1, 2018 and were adopted by applying the modified retrospective transition approach to contracts which were not completed as of the date of adoption. The adoption did not result in a cumulative effect adjustment to retained earnings on January 1, 2018.

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. Besides those noted below, there were no other significant updates or revisions to our policies during the six months ended June 30, 2018.

Revenue Recognition

Our operating revenues are primarily derived from the following activities:

- sales of natural gas, NGLs, condensate, crude oil and petroleum products;
- services related to compressing, gathering, treating and processing of natural gas; and
- services related to NGL fractionation, terminaling and storage, transportation and treating.

We have multiple types of contracts with commercial counterparties and many of these may result in cash inflows to Targa due to the structure of settlement provisions with embedded fees. The commercial relationship of the counterparty in such contracts is inherently one of a supplier, rather than a customer, and therefore, such contracts are excluded from the provisions of the revenue recognition guidance in Topic 606. Any cash inflows or fees that are realized on these supply type contracts are reported as a reduction of Product purchases.

Our revenues, therefore, are measured based on consideration specified in a contract with parties designated as customers. We recognize revenue when we satisfy a performance obligation by transferring control over a commodity or service to a customer. Sales and other taxes we collect, that are both imposed on and concurrent with revenue-producing activities, are excluded from revenues.

We generally report sales revenues on a gross basis in our Consolidated Statements of Operations, as we typically act as the principal in the transactions where we receive and control commodities. However, buy-sell transactions that involve purchases and sales of inventory with the same counterparty, which are legally contingent or in contemplation of one another, as well as other instances where we do not control the commodities, but rather are acting as an agent to the supplier, are reported as a single revenue transaction on a combined net basis.

Our commodity sales contracts typically contain multiple performance obligations, whereby each distinct unit of commodity to be transferred to the customer is a separate performance obligation. Under such contracts, revenue is recognized at the point in time each unit is transferred to the customer because the customer is able to direct the use of, and obtain substantially all of the remaining benefits from, the commodity at that time. In certain instances, it may be determinable that the customer receives and consumes the benefits of each unit as it is transferred. Under such contracts, we have a single performance obligation comprised of a series of distinct units of commodity; and in such instance, revenue is recognized over time using the units delivered output method, as each distinct unit is transferred to the customer. Our commodity sales contracts are typically priced at a market index, but may also be set at a fixed price. When our sales are priced at a market index, we apply the allocation exception for variable consideration and allocate the market price to each distinct unit when it is transferred to the customer. The fixed price in our commodity sales contracts generally represents the standalone selling price, and therefore, when each distinct unit is transferred to the customer, we recognize revenue at the fixed price.

Our service contracts typically contain a single performance obligation. The underlying activities performed by us are considered inputs to an integrated service and not separable because such activities in combination are required to successfully transfer the single overall service that the customer has contracted for and expects to receive. Therefore, the underlying activities in such contracts are not considered to be distinct services. However, in certain instances, the customer may contract for additional distinct services and therefore additional performance obligations may exist. In such instances, the transaction price is allocated to the multiple performance obligations based on their relative standalone selling prices. The performance obligation(s) in our service contracts is a series of distinct days of the applicable service over the life of the contract (fundamentally a stand-ready service), whereby we recognize revenue over time using an output method of progress based on the passage of time (i.e., each day of service). This output method is appropriate because it directly relates to the value of service transferred to the customer to date, relative to the remaining days of service promised under the contract.

The transaction price for our service contracts is typically comprised of variable consideration, which is primarily dependent on the volume and composition of the commodities delivered and serviced. The variable consideration is generally commensurate with our efforts to perform the service and the terms of the variable payments relate specifically to our efforts to satisfy each day of distinct service. Therefore, the variable consideration is typically not estimated at contract inception, but rather the allocation exception for variable consideration is applied, whereby the variable consideration is allocated to each day of service and recognized as revenue when each day of service is provided. When we are entitled to noncash consideration in the form of commodities, the variability related to the form of consideration (market price) and reasons other than form (volume and composition) are interrelated to the service, and therefore, we measure the noncash consideration at the point in time when the volume, mix and market price related to the commodities retained in-kind are known. This results in the recognition of revenue based on the market price of the commodity when the service is performed. In addition, if the transaction price includes a fixed component (i.e., a fixed capacity reservation fee), the fixed component is recognized ratably on a straight line basis over the contract term, as each day of service has elapsed, which is consistent with the output method of progress selected for the performance obligation.

Our customers are typically billed on a monthly basis, or earlier, if final delivery and sale of commodities is made prior to month-end, and payment is typically due within 10 to 30 days. As a practical matter, we define the unit of account for revenue recognition purposes based on the passage of time ranging from one month to one quarter, rather than each day. This is because the financial reporting outcome is the same regardless of whether each day or month/quarter is treated as the distinct service in the series. That is, at the end of each month or quarter, the variability associated with the amount of consideration for which we are entitled to, is resolved, and can be included in that month or quarter's revenue.

Significant Judgments

Certain provisions of our service contracts (i.e., tiered price structures) require further assessment to determine if the allocation exception for variable consideration is met. If the allocation exception is not met, we estimate the total consideration that we expect to be entitled to for the applicable term of the contract, based on projections of future activity. In such instance, revenue is recognized using an output method of progress based on the volume of commodities serviced during the reporting period. Our estimate of total consideration is reassessed each reporting period until contract completion.

For contracts with minimum volume commitments, we generally expect the customer to meet the commitment. However, such contracts are reassessed throughout the term of the commitment, and if we no longer expect the customer to meet the commitment, the allocation exception for variable consideration would not be met. That is, from that point onwards, an allocation based on the applicable fee applied to the volumes serviced does not depict the amount of consideration which we expect to be entitled to, in exchange for the service. In such instance, revenue will be recognized up to the minimum volume commitment in proportion to the days of service elapsed and the remaining duration of the commitment.

Contract Assets

Contract assets are presented separately from amounts presented as a receivable when or as a performance obligation(s) is satisfied and prior to having a right to payment that is unconditional at the end of the reporting period. We classify our contract assets as receivables because we generally have an unconditional right to payment for the commodities sold or services performed at the end of reporting period.

Note 4 – Newly-Formed Joint Ventures and Acquisitions

Joint Ventures

Grand Prix Joint Venture

In May 2017, we announced plans to construct Grand Prix, a new common carrier NGL pipeline. Grand Prix will transport volumes from the Permian Basin and our North Texas system to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. Grand Prix will be supported by our volumes and other third party customer commitments, and is expected to be fully in service in the second quarter of 2019.

In September 2017, we sold a 25% interest in our consolidated subsidiary, Grand Prix Pipeline LLC (the “Grand Prix Joint Venture”), which owns the portion of Grand Prix extending from the Permian Basin to Mont Belvieu, Texas, to funds managed by Blackstone Energy Partners ("Blackstone"). We are the operator and construction manager of Grand Prix. We account for Grand Prix on a consolidated basis in our consolidated financial statements.

Concurrent with the sale of the 25% interest in the Grand Prix Joint Venture to Blackstone, we and EagleClaw Midstream Ventures, LLC (“EagleClaw”), a Blackstone portfolio company, executed a long-term Raw Product Purchase Agreement whereby EagleClaw has dedicated and committed significant NGLs associated with EagleClaw’s natural gas volumes produced or processed in the Delaware Basin.

In March 2018, we announced an extension of Grand Prix into southern Oklahoma. The pipeline expansion is supported by long-term commitments for both transportation and fractionation services from our existing and future processing plants in the Arkoma area in our SouthOK system and from third-party commitments, including a long-term commitment for transportation and fractionation with Valiant Midstream, LLC. The extension of Grand Prix into southern Oklahoma is not part of the Grand Prix Joint Venture and its expected cost of approximately $350 million will be funded exclusively by Targa.

The capacity of the 24-inch pipeline segment from the Permian Basin will be approximately 300 MBbl/d, expandable to 550 MBbl/d. The pipeline segment from the Permian Basin will be connected to a 30-inch diameter pipeline segment in North Texas, where Permian, North Texas and Oklahoma volumes will be connected to Mont Belvieu, and will have capacity of approximately 450 MBbl/d, expandable to 950 MBbl/d. The capacity from southern Oklahoma to North Texas will vary based on telescoping pipe size.

Grand Prix economics related to volumes flowing on the pipeline from the Permian Basin to Mont Belvieu are included in the Blackstone and Grand Prix Development LLC (“Grand Prix DevCo JV”) joint venture arrangements, while the economics related to volumes flowing from North Texas and southern Oklahoma to Mont Belvieu accrue solely to Targa’s benefit.

The total cost for Grand Prix, including the extension into southern Oklahoma, is expected to be approximately $1.7 billion.

Cayenne Joint Venture

In July 2017, we entered into the Cayenne Pipeline, LLC joint venture (“Cayenne Joint Venture”) with American Midstream LLC to convert an existing 62-mile gas pipeline to an NGL pipeline connecting the VESCO plant in Venice, Louisiana to the Enterprise Products Operating LLC (“Enterprise”) pipeline at Toca, Louisiana, for delivery to Enterprise’s Norco Fractionator. We acquired a 50% interest in the Cayenne Joint Venture for $5.0 million. The project commenced operations in December 2017. See Note 7 – Investments in Unconsolidated Affiliates for activity related to the Cayenne Joint Venture.

Gulf Coast Express Joint Venture

In December 2017, we entered into definitive joint venture agreements with Kinder Morgan Texas Pipeline LLC (“KMTP”) and DCP Midstream Partners, LP (“DCP”) with respect to the joint development of Gulf Coast Express Pipeline (“GCX”), a natural gas pipeline from the Waha hub to Agua Dulce, Texas. The pipeline will provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. We and DCP each own a 25% interest, and KMTP owns a 50% interest in GCX. In addition, Apache Corporation (which will also be a shipper on GCX) has an option to purchase up to a 15% equity stake from KMTP. KMTP will serve as the operator and constructor of GCX, and we will commit significant volumes to the pipeline. In addition, Pioneer Natural Resources Company, a joint owner in our WestTX Permian Basin system has committed volumes to the project. GCX is designed to transport up to 1.98 Bcf/d of natural gas and the total cost of the project is expected to be approximately $1.75 billion. GCX is expected to be in service in the fourth quarter of 2019, pending the receipt of necessary regulatory approvals. See Note 7 – Investments in Unconsolidated Affiliates for activity related to the GCX Joint Venture.

Little Missouri 4 Joint Venture

In January 2018, we formed a 50/50 joint venture with Hess Midstream Partners LP to construct a new 200 MMcf/d natural gas processing plant (“LM4 Plant”) at Targa’s existing Little Missouri facility (“Little Missouri 4”). The LM4 Plant is anticipated to be completed at the end of the fourth quarter of 2018. Targa will manage construction of, and operate, the LM4 Plant. See Note 7 – Investments in Unconsolidated Affiliates for activity related to the Little Missouri 4 Joint Venture.

DevCo Joint Ventures

In February 2018, we formed three development joint ventures (“DevCo JVs”) with investment vehicles affiliated with Stonepeak Infrastructure Partners (“Stonepeak”) to fund portions of Grand Prix, GCX and an approximately 100 MBbl/d fractionator in Mont Belvieu, Texas (“Train 6”). Stonepeak owns a 95% interest in the Grand Prix DevCo JV, which owns a 20% interest in the Grand Prix Joint Venture (which does not include the extension into southern Oklahoma).

Stonepeak owns an 80% interest in both Targa GCX Pipeline LLC ("GCX DevCo JV"), which owns our 25% interest in GCX, and Targa Train 6 LLC ("Train 6 DevCo JV"), which owns a 100% interest in certain assets associated with Train 6. The Train 6 DevCo JV does not include certain fractionation-related infrastructure such as brine and storage, which will be funded and owned 100% by us. We hold the remaining interests in the DevCo JVs as well as control the management, construction and operation of Grand Prix and Train 6.

The following diagram displays the ownership structure of the DevCo JVs:

For a four-year period beginning on the earlier of the date that all three projects have commenced commercial operations or January 1, 2020, we have the option to acquire all or part of Stonepeak's interests in the DevCo JVs. Targa may acquire up to 50% of Stonepeak's invested capital in multiple increments with a minimum of $100 million, and Stonepeak's remaining 50% interest in a single final purchase. The purchase price payable for such partial or full interests is based on a predetermined fixed return or multiple on invested capital, including distributions received by Stonepeak from the DevCo JVs. Targa will control the management of the DevCo JVs unless and until Targa declines to exercise its option to acquire Stonepeak's interests. Train 6 is expected to begin operations in the first quarter of 2019. Grand Prix is expected to be in service in the second quarter of 2019. GCX is expected to be in service in the fourth quarter of 2019, pending the receipt of necessary regulatory approvals.

We hold a controlling interest in each of the DevCo JVs, as we have the majority voting interest and the supermajority voting provisions of the joint venture agreements do not represent substantive participating rights and are protective in nature to Stonepeak. As a result, we have consolidated each of the DevCo JVs in our financial statements. We continue to account for Grand Prix and Train 6 on a consolidated basis in our consolidated financial statements, and continue to account for GCX as an equity method investment as disclosed in Note 7 – Investments in Unconsolidated Affiliates.

Agua Blanca Joint Venture

In April 2018, we joined WhiteWater Midstream, LLC ("WhiteWater Midstream"), WPX Energy, Inc., and Markwest Energy Partners, L.P., as joint venture partners in WhiteWater Midstream's Delaware Basin Agua Blanca pipeline ("Agua Blanca Joint Venture"). The Agua Blanca pipeline is an approximately 160 mile natural gas residue pipeline with an initial capacity of 1.4 Bcf/d. The pipeline, which commenced operations in April 2018, runs from Orla, Texas to the Waha hub, servicing portions of Culberson, Loving, Pecos, Reeves and Ward counties with multiple direct downstream connections including to the Trans-Pecos Header. We acquired a 10% interest in the Agua Blanca Joint Venture for $3.5 million. See Note 7 – Investments in Unconsolidated Affiliates for activity related to the Agua Blanca Joint Venture.

Carnero Joint Venture

In May 2018, Sanchez Midstream Partners LP and we merged our respective 50% interests in the Carnero Gathering and Carnero Processing Joint Ventures, which own the high-pressure Carnero gathering line and Raptor natural gas processing plant, to form an expanded 50/50 joint venture in South Texas (the "Carnero Joint Venture"). In connection with the joint venture merger transactions, the Carnero Joint Venture acquired our 200 MMcf/d Silver Oak II natural gas processing plant located in Bee County Texas, which increased the processing capacity of the joint venture from 260 MMcf/d to 460 MMcf/d. Additional enhancements to the prior joint ventures include dedication of over 315,000 additional gross acres in the Western Eagle Ford, operated by Sanchez Energy Corporation, under a new long-term firm gas gathering and processing agreement. Including the approximately 105,000 Catarina acreage, the joint venture now has over 420,000 gross acres dedicated long term. We operate the gas gathering and processing facilities in the joint venture. The Carnero Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

Subsequent Event

In August 2018, we announced, along with NextEra Energy Pipeline Holdings, LLC (“NextEra”), WhiteWater Midstream, LLC, and MPLX, LP (collectively, the “Whistler participants”), the execution of a letter of intent for the joint development of the Whistler Pipeline (“Whistler”) which would provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. Whistler is designed to transport approximately 2.0 Bcf/d of natural gas from the Waha hub to Agua Dulce, TX, with an additional segment continuing from Agua Dulce to Wharton County, TX. Supply for Whistler would be sourced from multiple upstream connections in both the Midland and Delaware basins, including direct connections to Targa plants and the Agua Blanca pipeline. Whistler would be supported by collective commitments in excess of 1.5 Bcf/d from the Whistler participants and their respective producer customers, and would be constructed by NextEra. Targa would operate the pipeline, which is scheduled to begin operation in the fourth quarter of 2020, pending the completion of definitive agreements, final investment decisions by the Whistler participants, and regulatory approvals.

Acquisitions

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. The first earn-out payment due in May 2018 expired with no required payment. The second potential earn-out payment would occur in May 2019 and will be based upon a multiple of realized gross margin from contracts that existed on March 1, 2017.

Pro Forma Impact of Permian Acquisition on Consolidated Statements of Operations

The following summarized unaudited pro forma Consolidated Statements of Operations information for the three and six months ended June 30, 2017 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.

	Three Months Ended June 30, 2017 Pro Forma	Six Months Ended June 30, 2017 Pro Forma
Revenues	$1,867.7	$3,994.4
Net income (loss)	70.7	(41.2)

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 fair value of intangible assets recognized as part of the Permian Acquisition.

- 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 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 three and six months ended June 30, 2017.

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

Contingent Consideration

A contingent consideration liability arising from potential earn-out payments in connection with the Permian Acquisition has been recognized at its fair value. We agreed to pay up to an additional $935.0 million in aggregate potential earn-out payments in May 2018 and May 2019. The 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 the liability (that were not accounted for as revisions of the acquisition date fair value) have been included in Other income (expense).

During the three months ended June 30, 2018 and 2017, we recognized $60.6 million income and $2.1 million income in Other income (expense) related to the change in fair value of the contingent consideration. The decrease in fair value of the contingent consideration during the three months ended June 30, 2018 was primarily attributable to lower forecasted volumes for the remainder of the earn-out period, partially offset by a shorter discount period. The underlying forecasted volumes reflect the most recently observed production trends. During the six months ended June 30, 2018 and 2017, we recognized $4.6 million income and $1.1 million expense in Other income (expense) related to the change in fair value of the contingent consideration.

The portion of the earn-out due in 2018 expired with no required payment. As of June 30, 2018, the fair value of the second potential earn-out payment of $312.4 million has been recorded as a component of Accounts payable and accrued liabilities, which are current liabilities on our Consolidated Balance Sheets. See Note 16 – Fair Value Measurements for additional discussion of the fair value methodology.

Note 5 — Inventories

	June 30, 2018	December 31, 2017
Commodities	$ 155.6	$ 191.6
Materials and supplies	25.8	12.9
	$ 181.4	$ 204.5

Note 6 — Property, Plant and Equipment and Intangible Assets

	June 30, 2018	December 31, 2017	Estimated Useful Lives (In Years)
Gathering systems	$7,193.0	$ 7,037.2	5 to 20
Processing and fractionation facilities	3,687.2	3,569.6	5 to 25

Terminaling and storage facilities	1,313.4	1,244.1	5 to 25
Transportation assets	392.1	343.6	10 to 25
Other property, plant and equipment	312.0	303.7	3 to 25
Land	144.3	125.7	—
Construction in progress	2,409.0	1,581.5	—
Property, plant and equipment	15,451.0	14,205.4	
Accumulated depreciation	(4,029.7)	(3,775.4)	
Property, plant and equipment, net	$11,421.3	$ 10,430.0	
Intangible assets	$2,736.6	$ 2,736.6	10 to 20
Accumulated amortization	(662.3)	(570.8)	
Intangible assets, net	$2,074.3	$ 2,165.8	

Intangible Assets

Intangible assets consist of customer contracts and customer relationships acquired in the Permian Acquisition and the acquisition of the Flag City Plant assets in SouthTX 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.

Amortization expense attributable to these assets is recorded over the periods in which we benefit from services provided to customers. We are amortizing these assets over lives ranging from 10 to 20 years using a method that closely reflects the cash flow pattern underlying their intangible asset valuation, or the straight-line method, if a reliably determinable pattern of amortization could not be identified.

The estimated annual amortization expense for intangible assets is approximately $182.6 million, $171.6 million, $159.4 million, $149.5 million and $141.2 million for each of the years 2018 through 2022.

The changes in our intangible assets are as follows:

Balance at December 31, 2017	$2,165.8
Amortization	(91.5)
Balance at June 30, 2018	$2,074.3

Asset Sale

During the second quarter of 2018, we sold our inland marine barge business to a third party for approximately $69.3 million. As a result of the sale, we recognized a gain of $48.1 million in our Consolidated Statements of Operations for the three months ended June 30, 2018 as part of Other operating (income) expense. We continue to own and operate two ocean-going barges.

Note 7 – Investments in Unconsolidated Affiliates

Our investments in unconsolidated affiliates consist of the following:

- a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP (“GCF”);
- three non-operated joint ventures in South Texas acquired in the Atlas mergers in 2015: a 75% interest in T2 LaSalle Gathering Company L.L.C. (“T2 LaSalle”), a gas gathering company; a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (“T2 Eagle Ford”), a gas gathering company; and a 50% interest in T2 Cogeneration Holdings L.L.C. (T2 EF Cogen”), which owns a cogeneration facility, (together the “T2 Joint Ventures”);
- a 50% operated ownership interest in the Cayenne Joint Venture;
- a 25% non-operated ownership interest in GCX;
- a 50% operated ownership interest in Little Missouri 4; and
- a 10% non-operated ownership interest in the Agua Blanca Joint Venture.

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.

GCX, Little Missouri 4, Cayenne, and Agua Blanca Joint Ventures

See Note 4 – Newly-Formed Joint Ventures and Acquisitions for discussion of the formation of our GCX Joint Venture and Little Missouri 4 Joint Venture, and our acquisition of interests in the Cayenne Joint Venture and the Agua Blanca Joint Venture.

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

	Balance at December 31, 2017	Equity Earnings (Loss)	Cash Distributions (1)	Acquisition	Contributions (2)	Balance at June 30, 2018
GCF	$ 45.8	$ 9.1	$ (11.1)	$ —	$ —	$ 43.8
T2 LaSalle (3)	54.1	(2.6)	—	—	0.1	51.6
T2 Eagle Ford (3)	109.2	(5.0)	—	—	—	104.2
T2 EF Cogen	3.9	(0.9)	—	—	—	3.0
Cayenne	8.6	2.8	(0.6)	—	3.8	14.6
GCX	—	—	—	—	101.4	101.4
Little Missouri 4	—	—	(8.0)	—	49.3	41.3
Agua Blanca	—	—	—	3.5	0.5	4.0
Total	$ 221.6	$ 3.4	$ (19.7)	$ 3.5	$ 155.1	$ 363.9

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(1) Includes $2.0 million in distributions received from GCF in excess of our share of cumulative earnings for the six months ended June 30, 2018. 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. Also includes an $8.0 million distribution from Little Missouri 4 as a reimbursement of pre-formation expenditures.
(2) Includes a $16.0 million initial contribution of property, plant and equipment to Little Missouri 4. See Note 21 – Supplemental Cash Flow Information. Also includes $0.9 million of capitalized interest attributable to our investment in GCX.
(3) The carrying values of the T2 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, 2018, $25.4 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 8 — Accounts Payable and Accrued Liabilities

	June 30, 2018	December 31, 2017
Commodities	$729.5	$ 711.5
Other goods and services	382.5	289.7
Interest	85.9	54.4
Income and other taxes	58.5	27.1
Permian Acquisition contingent consideration, estimated current portion	312.4	6.8
Compensation and benefits	42.7	52.8
Preferred Series A dividends payable	22.9	22.9
Other	35.7	21.7
	$1,670.1	$ 1,186.9

Accounts payable and accrued liabilities includes $60.8 million and $50.4 million of liabilities to creditors to whom we have issued checks that remained outstanding as of June 30, 2018 and December 31, 2017. The current portion of the estimated Permian Acquisition contingent consideration represents the fair value of the earn-out payments due within twelve months of the respective balance sheet dates.

Note 9 — Debt Obligations

	June 30, 2018	December 31, 2017
Current:		
Obligations of the Partnership: (1)		
Accounts receivable securitization facility, due December 2018 (2)	$180.0	$ 350.0
Long-term:		
TRC obligations:		
TRC Senior secured revolving credit facility, variable rate, due June 2023 (3)	150.0	435.0
Obligations of the Partnership: (1)		
Senior secured revolving credit facility, variable rate, due June 2023 (4)	—	20.0
Senior unsecured notes:		
4 % fixed rate, due November 2019	749.4	749.4
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 April 2026	1,000.0	—
5 % fixed rate, due February 2027	500.0	500.0
5% fixed rate, due January 2028	750.0	750.0
TPL notes, 4¾% fixed rate, due November 2021	6.5	6.5
TPL notes, 5 % fixed rate, due August 2023	48.1	48.1
Unamortized premium	0.4	0.4
	5,428.0	4,733.0
Debt issuance costs, net of amortization	(35.5)	(30.0)
Long-term debt	5,392.5	4,703.0
Total debt obligations	$5,572.5	$ 5,053.0
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)	71.5	27.2
	$71.5	$ 27.2

(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.

(2) As of June 30, 2018, the Partnership had $346.2 million of qualifying receivables under its $350.0 million accounts receivable securitization facility, resulting in availability of $166.2 million.

(3) As of June 30, 2018, availability under TRC’s $670.0 million senior secured revolving credit facility (“TRC Revolver”) was $520.0 million.
(4) As of June 30, 2018, availability under the Partnership’s $2.2 billion senior secured revolving credit facility (“TRP Revolver”) was $2,128.5 million.

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, 2018:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC Revolver	3.3% - 3.8%	3.5%
TRP Revolver	3.4% - 5.5%	3.8%
Partnership's accounts receivable securitization facility	2.6% - 3.1%	2.8%

Compliance with Debt Covenants

As of June 30, 2018, we were in compliance with the covenants contained in our various debt agreements.

Senior Unsecured Notes

In April 2018, the Partnership issued $1.0 billion aggregate principal amount of 5 % senior notes due April 2026 (the "5 % Senior Notes due 2026"). The Partnership used the net proceeds of $991.9 million after costs from this offering to repay borrowings under its credit facilities and for general partnership purposes. The 5 % Senior Notes due 2026 are unsecured senior obligations that have substantially the same terms and covenants as the Partnership's other senior notes.

TRC Revolver Amendment

In June 2018, we entered into an agreement to amend the TRC Revolver to extend the maturity date from February 2020 to June 2023. The available commitments of $670.0 million and our ability to request additional commitments of $200.0 million remained unchanged. The TRC Revolver continues to bear interest costs that are dependent on the ratio of non-Partnership consolidated funded indebtedness to consolidated adjusted EBITDA, as defined in the TRC Revolver, and the covenants remained substantially the same.

We incurred a loss of $0.7 million to partially write off debt issuance costs associated with the TRC Revolver as a result of a change in syndicate members. The remaining debt issuance costs, along with debt issuance costs incurred with this amendment, will be amortized on a straight-line basis over the TRC Revolver's new term.

TRP Revolver Amendment

In June 2018, the Partnership entered into an agreement to amend and restate the TRP Revolver, which extended the maturity date from October 2020 to June 2023, increased available commitments from $1.6 billion to $2.2 billion and lowered the applicable margin range and commitment fee range used in the calculation of interest. The Partnership's ability to request additional commitments of $500.0 million remained unchanged.

The TRP Revolver bears interest, at the Partnership's option, either at the base rate or the Eurodollar rate. The base rate is equal to the highest of: (i) Bank of America's prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin (a) before the collateral release date, ranging from 0.25% to 1.25% dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA and (b) upon and after the collateral release date, ranging from 0.125% to 0.75% dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings. The Eurodollar rate is equal to LIBOR rate plus an applicable margin (i) before the collateral release date, ranging from 1.25% to 2.25% dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA and (ii) upon and after the collateral release date, ranging from 1.125% to 1.75% dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings.

The Partnership is required to pay a commitment fee equal to an applicable rate ranging from (a) before the collateral release date, 0.25% to 0.375% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA) and (b) upon and after the collateral release date, 0.125% to 0.35% (dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings) times the actual daily average unused portion of the TRP Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable rate ranging plus an applicable margin (i) before the collateral release date, ranging from 1.25% to 2.25% dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA and (ii) upon and after the collateral release date, ranging from 1.125% to 1.75% dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings. The TRP Revolver's covenants remained substantially the same.

The Partnership incurred a loss of $1.3 million to partially write-off debt issuance costs associated with the TRP Revolver amendment as a result of a change in syndicate members. The remaining debt issuance costs, along with debt issuance costs incurred with this amendment, will be amortized on a straight-line basis over the TRP Revolver's new term.

Note 10 — Other Long-term Liabilities

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

	June 30, 2018	December 31, 2017
Asset retirement obligations	$ 53.1	$ 50.8
Mandatorily redeemable preferred interests	1.2	76.2
Deferred revenue	134.3	136.2
Permian Acquisition contingent consideration, noncurrent portion	—	310.2
Other liabilities	26.2	24.5
Total long-term liabilities	$ 214.8	$ 597.9

Asset Retirement Obligations

Our asset retirement obligations ("ARO") primarily relate to certain gas gathering pipelines and processing facilities.

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. As redemption cannot occur before 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, 2018.

In February 2018, the parties amended the agreements governing each joint venture to: (i) increase the priority return for capital contributions made on or after January 1, 2017; and (ii) add a non-consent feature effective with respect to certain capital projects undertaken on or after January 1, 2017. During the six months ended June 30, 2018, the change in the estimated redemption value of the mandatorily redeemable preferred interests is primarily attributable to the amendments.

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., then a subsidiary of Noble Group Ltd., entered into a long-term, fee-based agreement (the “Splitter Agreement”) under which we will build and operate a crude oil and condensate splitter at our Channelview Terminal on the Houston Ship Channel (the “Channelview Splitter”) and provide approximately 730,000 Bbl of storage capacity. The Channelview Splitter will have the capability to split approximately 35,000 Bbl/d 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 substantially completed in the late third quarter or early fourth quarter of 2018, and has an estimated total cost of approximately $140 million. In January 2018, Vitol US Holding Co. acquired Noble Americas Corp.

Deferred revenue also includes nonmonetary consideration received in a 2015 amendment to a gas gathering and processing agreement and consideration received for other construction activities of facilities connected to our systems.

The following table shows the changes in deferred revenue:

Balance at December 31, 2017	$136.2
Additions	0.1
Revenue recognized	(2.0)
Balance at June 30, 2018	$134.3

Permian Acquisition Contingent Consideration

Upon closing of the Permian Acquisition, a contingent consideration liability arising from potential earn-out provisions was recognized at its preliminary fair value. See Note 4 – Newly-Formed Joint Ventures and Acquisitions. The first potential earn-out payment would have occurred in May 2018 while the second potential earn-out payment would occur in May 2019. The acquisition date fair value of the contingent consideration of $416.3 million was recorded within Other long-term liabilities on our Consolidated Balance Sheets. For the period from the acquisition date to December 31, 2017, the fair value of the contingent consideration decreased by $99.3 million, bringing the total Permian Acquisition contingent consideration to $317.0 million at December 31, 2017, of which $6.8 million was a current liability.

The portion of the earn-out due in 2018 expired with no required payment. For the period from December 31, 2017 to June 30, 2018, the fair value of the contingent consideration decreased by $4.6 million. As of June 30, 2018, the fair value of the second potential earn-out payment of $312.4 million has been recorded as a component of accounts payable and accrued liabilities, which are current liabilities on our Consolidated Balance Sheets. See Note 16 – Fair Value Measurements for additional discussion of the fair value methodology.

Note 11 – Preferred Stock

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").

Preferred Stock Dividends

As of June 30, 2018, we have accrued cumulative preferred dividends of $22.9 million on our Series A Preferred Stock, which will be paid on August 14, 2018. During the three and six months ended June 30, 2018, we paid $22.9 million and $45.8 million of dividends at $23.75 per share to preferred shareholders, and recorded deemed dividends of $7.2 million and $14.1 million attributable to accretion of the preferred discount resulting from the beneficial conversion feature ("BCF") accounting. Such accretion is included in the book value of the Series A Preferred Stock.

Note 12 — Common Stock and Related Matters

Public Offerings of Common Stock

For the six months ended June 30, 2018, we issued 4,405,867 shares of common stock under our Equity Distribution Agreement entered into in December 2016 (the "December 2016 EDA"), receiving net proceeds of $214.8 million. As of June 30, 2018, we have $107.7 million remaining under the December 2016 EDA.

On May 9, 2017, we entered into an equity distribution agreement under the universal shelf registration statement filed in May 2016 (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, 2018, we issued 3,274,128 shares of common stock under the May 2017 EDA, receiving net proceeds of $154.8 million. As of June 30, 2018, we have $594.0 million remaining under the May 2017 EDA.

Warrants

As of December 31, 2017, 19,983,843 Warrants from the 2016 Series A Preferred offering had been exercised and net settled for 11,336,856 shares of common stock, with 99,888 Warrants remaining. During the three months ended March 31, 2018, the remaining Warrants were exercised and net settled by us for 58,814 shares of common stock.

Common Stock Dividends

The following table details the dividends declared and/or paid by us to common shareholders for the six months ended June 30, 2018.

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)	Dividends Declared per Share of Common Stock
(In millions, except per share amounts)					
June 30, 2018	August 15, 2018	$ 208.9	$ 205.2	$ 3.7	$ 0.91000
March 31, 2018	May 16, 2018	203.1	199.7	3.4	0.91000
December 31, 2017	February 15, 2018	202.4	199.1	3.3	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 13 — Partnership Units and Related Matters

Distributions

We are entitled to receive all Partnership distributions from available cash on the Partnership's common units after payment of preferred unit distributions each quarter.

The following table details the distributions declared or paid by the Partnership for the six months ended June 30, 2018.

Three Months Ended	Date Paid Or to Be Paid	Total Distributions	Distributions to Targa Resources Corp.
June 30, 2018	August 13, 2018	$ 234.0	$ 231.2
March 31, 2018	May 11, 2018	229.7	226.9
December 31, 2017	February 12, 2018	228.5	225.7

Contributions

All capital contributions continue to be allocated 98% to the limited partner and 2% to the general partner; however, no units will be issued for those contributions. During the six months ended June 30, 2018, we made total capital contributions to the Partnership of $80.1 million.

Preferred Units

Preferred Units rank senior to the Partnership's common units with respect to the distribution rights. Distributions on the Partnership's 5,000,000 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, 2018. The Preferred Units are reported as noncontrolling interests in our financial statements.

Subsequent Event

In July 2018, the board of directors of the general partner of the Partnership declared a cash distribution of $0.1875 per Preferred Unit, resulting in approximately $0.9 million in distributions that will be paid on August 15, 2018.

Note 14 — Earnings per Common Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income	$121.1	$70.6	$160.0	$(39.9)
Less: Net income attributable to noncontrolling interests	12.0	13.0	28.0	21.8
Less: Dividends on preferred stock	30.1	29.2	59.9	58.3
Net income attributable to common shareholders for basic earnings per share	$79.0	$28.4	$72.1	$(120.0)
Weighted average shares outstanding - basic	221.1	203.7	219.9	197.8
Net income available per common share - basic	$0.36	$0.14	$0.33	$(0.61)
Weighted average shares outstanding	221.1	203.7	219.9	197.8
Dilutive effect of common stock equivalents (1)	1.7	1.3	1.6	—
Weighted average shares outstanding - diluted	222.8	205.0	221.5	197.8
Net income available per common share - diluted	$0.35	$0.14	$0.33	$(0.61)

(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 convertible preferred stock. 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,	
	2018	2017	2018	2017
Unvested restricted stock awards	—	0.2	—	1.2
Warrants to purchase common stock (1)	—	—	—	0.1
Series A Preferred Stock (2)	46.5	46.5	46.5	46.5

(1) During the three months ended March 31, 2018, the remaining Warrants were exercised and net settled by us for shares of common stock.

(2) 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.

Note 15 — Derivative Instruments and Hedging Activities

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have hedged the commodity prices associated with a portion of our expected (i) natural gas, 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.

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, 2018, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2018	2019	2020	2021
Natural Gas	Swaps	MMBtu/d	170,740	131,506	15,500	3,822
Natural Gas	Basis Swaps	MMBtu/d	135,842	97,377	30,417	16,658
NGL	Swaps	Bbl/d	23,300	17,469	7,807	550
NGL	Futures	Bbl/d	10,277	1,945	3,115	-
NGL	Options	Bbl/d	1,310	410	-	-
Condensate	Swaps	Bbl/d	4,990	3,413	770	190
Condensate	Options	Bbl/d	590	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 on 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, 2018		Fair Value as of December 31, 2017	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 53.4	$ 92.6	$ 37.9	$ 78.6
	Long-term	20.0	32.0	23.2	18.7
Total derivatives designated as hedging instruments		$ 73.4	$ 124.6	$ 61.1	$ 97.3
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 0.8	$ 10.6	$ —	$ 1.1
	Long-term	1.7	3.5	—	0.9
Total derivatives not designated as hedging instruments		$ 2.5	$ 14.1	$ —	$ 2.0
Total current position		$ 54.2	$ 103.2	$ 37.9	$ 79.7
Total long-term position		21.7	35.5	23.2	19.6
Total derivatives		$ 75.9	$ 138.7	$ 61.1	$ 99.3

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

	Gross Presentation			Pro Forma Net Presentation	
June 30, 2018	Asset	Liability	Collateral	Asset	Liability
Current Position					
Counterparties with offsetting positions or collateral	$54.2	$(93.4)	$ 14.9	$19.7	$(44.0)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(9.8)	-	-	(9.8)
	54.2	(103.2)	14.9	19.7	(53.8)
Long Term Position					
Counterparties with offsetting positions or collateral	21.7	(30.5)	-	9.0	(17.8)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(5.0)	-	-	(5.0)
	21.7	(35.5)	-	9.0	(22.8)
Total Derivatives					
Counterparties with offsetting positions or collateral	75.9	(123.9)	14.9	28.7	(61.8)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(14.8)	-	-	(14.8)
	$75.9	$(138.7)	$ 14.9	$28.7	$(76.6)

	Gross Presentation			Pro Forma Net Presentation	
December 31, 2017	Asset	Liability	Collateral	Asset	Liability
Current Position					
Counterparties with offsetting positions or collateral	$37.9	$(74.7)	$ 22.9	$13.8	$(27.7)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(5.0)	-	-	(5.0)
	37.9	(79.7)	22.9	13.8	(32.7)
Long Term Position					
Counterparties with offsetting positions or collateral	23.2	(17.3)	-	14.8	(8.9)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(2.3)	-	-	(2.3)
	23.2	(19.6)	-	14.8	(11.2)
Total Derivatives					
Counterparties with offsetting positions or collateral	61.1	(92.0)	22.9	28.6	(36.6)
Counterparties without offsetting positions - assets	-	-	-	-	-
Counterparties without offsetting positions - liabilities	-	(7.3)	-	-	(7.3)
	$61.1	$(99.3)	$ 22.9	$28.6	$(43.9)

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 liability of $62.8 million as of June 30, 2018. The estimated fair value is net of an adjustment for credit risk based on the default probabilities 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		Six Months	
	Ended June 30,		Ended June 30,	
Hedging Relationships	2018	2017	2018	2017
Commodity contracts	$ (103.0)	$ 29.8	$ (38.3)	$ 96.0

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	Gain (Loss) Reclassified from OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	2018	2017	2018	2017
Revenues	$ (7.8)	$ 5.7	$ (34.4)	$ (0.4)

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	Recognized in Income on	Three Months Ended June 30,		Six Months Ended June 30,	
as Hedging Instruments	Derivatives	2018	2017	2018	2017
Commodity contracts	Revenue	$(2.2)	$(0.4)	$(13.0)	$(1.4)

Based on valuations as of June 30, 2018, we expect to reclassify commodity hedge-related deferred losses of $51.1 million included in accumulated other comprehensive income into earnings before income taxes through the end of 2021, with $39.2 million of losses to be reclassified over the next twelve months.

See Note 16 – Fair Value Measurements and Note 22 – Segment Information for additional disclosures related to derivative instruments and hedging activities.

Note 16 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities (“financial instruments”). Derivative financial instruments and contingent consideration related to business acquisitions are reported at fair value on our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost on 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, 2018, a net liability position of $62.8 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 $151.5 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 $25.9 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. Long-term debt is primarily the other financial instrument for which carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- 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
- 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 on our Consolidated Balance Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	June 30, 2018				
	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)	$75.8	$75.8	$ —	$75.7	$0.1
Liabilities from commodity derivative contracts (1)	138.6	138.6	—	129.9	8.7
Permian Acquisition contingent consideration (2)	312.4	312.4	—	—	312.4
TPL contingent consideration (3)	2.5	2.5	—	—	2.5
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	281.6	281.6	—	—	—
TRC Revolver	150.0	150.0	—	150.0	—
TRP Revolver	—	—	—	—	—
Partnership's Senior unsecured notes	5,278.0	5,229.9	—	5,229.9	—
Partnership's accounts receivable securitization facility	180.0	180.0	—	180.0	—

	December 31, 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)	$60.3	$60.3	$ —	$58.8	$1.5
Liabilities from commodity derivative contracts (1)	98.5	98.5	—	93.3	5.2
Permian Acquisition contingent consideration (2)	317.0	317.0	—	—	317.0
TPL contingent consideration (3)	2.4	2.4	—	—	2.4
Financial Instruments Recorded on Our					

Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	137.2	137.2	—	—	—
TRC Revolver	435.0	435.0	—	435.0	—
TRP Revolver	20.0	20.0	—	20.0	—
Partnership's Senior unsecured notes	4,278.0	4,362.4	—	4,362.4	—
Partnership's accounts receivable securitization facility	350.0	350.0	—	350.0	—

(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 15 – Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.
(2) We have a contingent consideration liability related to the Permian Acquisition, which is carried at fair value. See Note 4 – Newly-Formed Joint Ventures and Acquisitions.
(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 on 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, 2018, we had 21 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) in our Consolidated Statements of Operations.

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

	Commodity Derivative Contracts Asset/(Liability)	Contingent Liability
Balance, December 31, 2017	$ (3.8)	$ (319.4)
Change in fair value of TPL contingent consideration	-	(0.1)
Change in fair value of Permian Acquisition contingent consideration (1)	-	4.6
New Level 3 derivative instruments	(0.3)	-
Settlements included in Revenue	0.8	-
Unrealized gain/(loss) included in OCI	(5.3)	-
Balance, June 30, 2018	$ (8.6)	$ (314.9)

(1) Represents the change in fair value between December 31, 2017 and June 30, 2018 of the contingent consideration that arose as part of the Permian Acquisition in the first quarter of 2017. See Note 4 – Newly-Formed Joint Ventures and Acquisitions for discussion of the initial fair value.

Note 17 – Related Party Transactions

Relationship with Sajet Resources LLC

In December 2010, immediately prior to Targa's initial public offering, Sajet Resources LLC ("Sajet") was spun-off from Targa. Certain directors and executive officers of Targa are also directors and executive officers of Sajet. The primary assets of Sajet are real property. Sajet also holds (i) an ownership interest in Floridian Natural Gas Storage Company, LLC through a December 2016 merger with Tesla Resources LLC, (ii) an ownership interest in Allied CNG Ventures LLC and (iii) certain technology rights. Former holders of our pre-IPO common equity, including certain of our current and former executives, managers and directors collectively own an 18% interest in Sajet. We provide general and administrative services to Sajet and are reimbursed for these amounts. Services provided to Sajet totaled less than $0.1 million in January and February of 2018.

In March 2018, we acquired the 82% interest in Sajet that was held by Warburg Pincus sponsored funds for $5.0 million in cash (the "Warburg Funds Transaction") and extinguished Sajet's third-party debt in exchange for a promissory note from Sajet of $9.9 million. Minority shareholders had the right to join the transaction and sell up to 100% of their membership interests in Sajet to us at substantially the same terms and price as the Warburg Funds Transaction (the "Tag-Along Rights"). Minority shareholders who currently hold, or formerly held, executive positions at Targa, and minority shareholders who are board members of Targa, agreed not to exercise their Tag-Along Rights resulting from the Warburg Funds Transaction. Certain minority shareholders chose to sell interests totaling 1.6% for approximately $0.1 million in April 2018.

Since March 2018, Sajet has been accounted for on a consolidated basis in our consolidated financial statements.

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 – Revenue

Fixed consideration allocated to remaining performance obligations

The following table includes the estimated minimum revenue expected to be recognized in the future related to performance obligations that are unsatisfied (or partially unsatisfied) at the end of the reporting period and is comprised of fixed consideration primarily attributable to contracts with minimum volume commitments and for which a guaranteed amount of revenue can be calculated. These contracts are comprised primarily of fractionation, export, terminaling and storage agreements.

	2018	2019	2020 and after
Fixed consideration to be recognized as of June 30, 2018	$225.4	$381.4	$1,510.9

In accordance with the optional exemptions that we elected to apply, the amounts presented in the table exclude variable consideration for which the allocation exception is met and consideration associated with performance obligations of short-term contracts. In addition, consideration from contracts for which we recognize revenue at the amount to which we have the right to invoice for services performed is also excluded from the table above, with the exception of any fixed consideration attributable to such contracts. The nature of the performance obligations for which the consideration has been excluded is consistent with the performance obligations described within our revenue recognition accounting policy and the estimated remaining duration of such contracts primarily ranges from 1 to 16 years. In addition, variability exists in the consideration excluded due to the unknown quantity and composition of volumes to be serviced or sold as well as fluctuations in the market price of commodities to be received as consideration or sold over the applicable remaining contract terms. Such variability is resolved at the end of each future month or quarter.

For additional information on our revenue recognition policy and the adoption of ASU No. 2014-09, see Note 3 – Significant Accounting Policies. For disclosures related to disaggregated revenue, see Note 22 – Segment Information.

Note 20 – Other Operating (Income) Expense

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017

(Gain) loss on sale or disposal of assets (1)	$(46.7)	$0.1	$(46.8)	$16.2
Miscellaneous business tax	0.3	0.2	0.6	0.3
Other	—	—	0.1	—
	$(46.4)	$0.3	$(46.1)	$16.5

(1) Comprised primarily of a $48.1 million gain on sale of our inland marine barge business to a third party during the second quarter of 2018. For additional information, see Note 6 — Property, Plant and Equipment and Intangible Assets. Also includes 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 2017 sale.

Note 21 - Supplemental Cash Flow Information

	Six Months Ended June 30, 2018	2017
Cash:		
Interest paid, net of capitalized interest (1)	$ 83.9	$ 109.2
Income taxes paid, net of refunds	(0.5)	(67.8)
Non-cash investing activities:		
Deadstock commodity inventory transferred to property, plant and equipment	$ 26.8	$ 8.3
Impact of capital expenditure accruals on property, plant and equipment	145.2	80.0
Transfers from materials and supplies inventory to property, plant and equipment	1.0	1.5
Contribution of property, plant and equipment to investments in unconsolidated affiliates	16.0	1.0
Change in ARO liability and property, plant and equipment due to revised cash flow estimate	1.2	3.1
Non-cash financing activities:		
Reduction of Owner's Equity related to accrued dividends on unvested equity awards under share compensation arrangements	$ 6.5	$ 4.6
Accrued tax withholding obligations	2.2	1.5
Accretion of deemed dividends on Series A Preferred Stock	14.1	12.5
Impact of accounting standard adoption recorded in retained earnings	5.2	56.1
Accrued distribution to noncontrolling interests	—	0.3
Non-cash balance sheet movements related to the Permian Acquisition (See Note 4 - Newly-Formed Joint Ventures and Acquisitions):		
Contingent consideration recorded at the acquisition date	$ —	$ 416.3
Non-cash balance sheet movements related to acquisition of related party:		
Noncontrolling interest	1.1	—

(1) Interest capitalized on major projects was $20.8 million and $4.1 million for the six months ended June 30, 2018 and 2017.

Note 22 — 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 reportable segments include operating segments that have been aggregated based on the nature of the products and services provided.

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 (including exposure to the SCOOP and STACK plays) 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 the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and 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. The Logistics and Marketing segment includes Grand Prix, which is currently under construction. The associated assets are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipeline projects and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the results of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are 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, 2018				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$273.6	$ 1,884.0	$(3.5)	$ —	$2,154.1
Fees from midstream services	176.0	114.3	—	—	290.3
	449.6	1,998.3	(3.5)	—	2,444.4
Intersegment revenues					
Sales of commodities	913.0	76.4	—	(989.4)	—
Fees from midstream services	1.7	8.4	—	(10.1)	—
	914.7	84.8	—	(999.5)	—
Revenues	$1,364.3	$ 2,083.1	$(3.5)	$ (999.5)	$2,444.4
Operating margin	$242.2	$ 129.9	$(3.5)	$ —	$368.6
Other financial information:					
Total assets (1)	$11,054.4	$ 4,293.5	$74.6	$ 173.6	$15,596.1
Goodwill	$256.6	$ —	$—	$ —	$256.6
Capital expenditures	$282.2	$ 418.2	$—	$ 34.4	$734.8

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(1) Assets in the Corporate and Eliminations column primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	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) Assets included in the Corporate and Eliminations column primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	Six Months Ended June 30, 2018				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$538.7	$ 3,810.1	$(21.4)	$ —	$4,327.4
Fees from midstream services	337.5	235.1	—	—	572.6
	876.2	4,045.2	(21.4)	—	4,900.0
Intersegment revenues					
Sales of commodities	1,779.2	131.5	—	(1,910.7)	—
Fees from midstream services	3.8	15.8	—	(19.6)	—
	1,783.0	147.3	—	(1,930.3)	—
Revenues	$2,659.2	$ 4,192.5	$(21.4)	$ (1,930.3)	$4,900.0
Operating margin	$463.3	$ 268.3	$(21.4)	$ (0.1)	$710.1
Other financial information:					
Total assets (1)	$11,054.4	$ 4,293.5	$74.6	$ 173.6	$15,596.1
Goodwill	$256.6	$ —	$—	$ —	$256.6
Capital expenditures	$555.4	$ 669.2	$—	$ 68.1	$1,292.7

(1) Assets included in the Corporate and Eliminations column 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) Assets included in the Corporate and Eliminations column primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

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

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Sales of commodities:				
Revenue recognized from contracts with customers:				
Natural gas	$416.4	$497.0	$886.6	$978.6
NGL	1,584.5	1,033.9	3,191.3	2,353.5
Condensate	103.5	47.4	190.4	91.0
Petroleum products	59.6	40.1	107.8	59.9
	2,164.0	1,618.4	4,376.1	3,483.0
Non-customer revenue:				
Derivative activities - Hedge	(7.7)	5.8	(35.7)	0.1
Derivative activities - Non-hedge (1)	(2.2)	(0.4)	(13.0)	(1.4)
	(9.9)	5.4	(48.7)	(1.3)
Total sales of commodities	2,154.1	1,623.8	4,327.4	3,481.7
Fees from midstream services:				
Revenue recognized from contracts with customers:				
Fractionating and treating	28.1	32.0	59.2	63.0
Storage, terminaling, transportation and export	85.3	72.9	174.0	172.7
Gathering and processing	173.7	122.7	325.8	230.5
Other	3.2	16.3	13.6	32.4
Total fees from midstream services	290.3	243.9	572.6	498.6
Total revenues	$2,444.4	$1,867.7	$4,900.0	$3,980.3

(1) Represents derivative activities that are not designated as hedging instruments under ASC 815.

The following table shows a reconciliation of reportable segment operating margin to income (loss) before income taxes for the periods presented:

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
Reconciliation of reportable segment operating margin to income (loss) before income taxes:				
Gathering and Processing operating margin	$ 242.2	$ 173.5	$ 463.3	$ 351.1
Logistics and Marketing operating margin	129.9	112.4	268.3	242.4
Other operating margin	(3.5)	6.0	(21.4)	4.9

Depreciation and amortization expenses	(202.6)	(203.4)	(400.7)	(394.6)
General and administrative expenses	(57.0)	(51.0)	(113.8)	(99.6)
Interest income (expense), net	(62.0)	(62.1)	(46.0)	(125.1)
Change in contingent considerations	60.6	2.1	4.5	(1.2)
Other, net	46.3	(12.9)	47.4	(52.7)
Income (loss) before income taxes	$ 153.9	$ (35.4)	$ 201.6	$ (74.8)

Note 23 – Income Taxes

On December 22, 2017, the United States enacted tax legislation referred to as the Tax Cuts and Jobs Act (the "Tax Act") which significantly changes United States corporate income tax laws beginning, generally, in 2018. These changes include, among others, (i) a permanent reduction of the United States corporate income tax rate from a top marginal rate of 35% to a flat rate of 21%, (ii) elimination of the corporate alternative minimum tax, (iii) immediate deductions for certain new investments instead of deductions for depreciation expense over time, (iv) limitation on the tax deduction for interest expense to 30% of adjusted taxable income, (v) limitation of the deduction for net operating losses to 80% of current year taxable income and elimination of net operating loss carrybacks, and (vi) elimination of many business deductions and credits, including the domestic production activities deduction, and the deduction for entertainment expenditures. We included the impacts of the Tax Act in the fourth quarter 2017 consolidated financial statements, and no changes were made to those provisional amounts during the six months ended June 30, 2018. We will continue to examine the impact of this legislation and future regulations. Additional impacts from the enactment of the Tax Act will be recorded as they are identified during the measurement period as provided for in SAB No. 118, which extends up to one year from the enactment date. The first and second quarter 2018 tax provision reflects the law changes noted above, including the new corporate tax rate of 21%.

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, 2017 ("Annual Report"), as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report on Form 10-Q.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). The amendments in this update supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. We adopted Topic 606 on January 1, 2018 by applying the modified retrospective transition approach to contracts which were not completed as of the date of adoption. The adoption of Topic 606 did not result in an impact to our operating or gross margin. However, the adoption did have an impact on the classification between "Fees from midstream services" and "Product purchases," as well as the reporting of gross vs. net revenues. For more information, see "Recent Accounting Pronouncements" included within Note 3 – Significant Accounting Policies in our Consolidated Financial Statements.

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.

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, terminaling and selling 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 (including exposure to the SCOOP and STACK plays) 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 the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and 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. The Logistics and Marketing segment includes Grand Prix, which is currently under construction. The associated assets, including these pipeline projects, are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipeline projects and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the results of commodity derivative activities related to Gathering and Processing hedges of equity volumes that are included in operating margin and mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges.

Recent Developments

Gathering and Processing Segment Expansion

Permian Midland Processing Expansions

In response to increasing production and to meet the infrastructure needs of producers, we have announced the construction of additional processing plants that further expand the gathering and processing footprint of our Permian Midland systems:

- In February 2018, we announced plans to construct two new cryogenic natural gas processing plants, each with a processing capacity of 250 MMcf/d. The first plant, known as the Hopson Plant, is expected to begin operations in the first quarter of 2019. The second plant, known as the Pembrook Plant, is expected to begin operations in the second quarter of 2019.
- In May 2017, we announced plans to build a new 200 MMcf/d cryogenic natural gas processing plant, known as the Johnson Plant, which is expected to begin operations in the third quarter of 2018.
- In November 2016, we announced plans to build the 200 MMcf/d Joyce Plant, which began operations in the first quarter of 2018.

Permian Delaware Processing Expansions

In March 2018, we announced that we entered into long-term fee-based agreements with an investment grade energy company for natural gas gathering and processing services in the Delaware Basin and for downstream transportation, fractionation and other related services. We will construct approximately 220 miles of 12- to 24-inch high pressure rich gas gathering pipelines across the Delaware Basin, a new 250 MMcf/d cryogenic natural gas processing plant (the “Falcon Plant”) in the Delaware Basin that is expected to begin operations in the fourth quarter of 2019, and a second 250 MMcf/d cryogenic natural gas processing plant in Culberson County (the “Peregrine Plant”) in the Delaware Basin that is expected to begin operations in the second quarter of 2020.

We will provide NGL transportation services on Grand Prix and fractionation services at our Mont Belvieu complex for a majority of the NGLs from the Falcon and Peregrine Plants. Total growth capital expenditures related to the plants and high pressure pipeline system are approximately $500 million, with approximately $200 million expected to be spent in 2018.

In May 2017, we announced plans to build a new plant and further expand the gathering footprint of our Permian Delaware systems. This project includes a new 250 MMcf/d cryogenic processing plant, known as the Wildcat Plant, which was completed in the second quarter of 2018.

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-based 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 in May 2018 and May 2019. The potential earn-out payments are based upon a multiple of realized gross margin from contracts that existed on March 1, 2017. The 2018 portion of the earn-out expired with no payment required.

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 initial New Delaware assets included 70 MMcf/d of processing capacity. In addition, the Oahu Plant, a 60 MMcf/d plant in the Delaware Basin, which was completed in March 2018 and placed into service in April 2018, was added to the New Delaware system. Currently, there is 40 MBbl/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 MBbl/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 New Midland's gas gathering and processing assets were connected to our WestTX system in the fourth quarter of 2017. We believe connecting the acquired assets to our legacy Permian footprint creates operational and capital synergies, and is expected to afford enhanced flexibility in serving producers.

Badlands

In January 2018, we announced the formation of a 50/50 joint venture with Hess Midstream Partners LP to construct a new 200 MMcf/d natural gas processing plant (“LM4 Plant”) at Targa’s existing Little Missouri facility. The LM4 Plant is anticipated to be completed at the end of the fourth quarter of 2018. Targa will manage construction of, and operate, the LM4 Plant.

SouthOK Expansion

In December 2017, ownership of the Flag City Plant assets located in Jackson County, Texas, was transferred to Centrahoma Processing, LLC, a joint venture that we operate (“Centrahoma” or the “Centrahoma Joint Venture”), and in which we have a 60% ownership interest; the remaining 40% ownership interest is held by MPLX, LP (“MPLX”). In conjunction with Targa’s contribution of the plant assets, MPLX made a cash contribution to Centrahoma in order to maintain its 40% ownership interest. The former Flag City Plant assets are being relocated to, and installed in, Hughes County, Oklahoma, as a new 150 MMcf/d cryogenic natural gas processing plant (the “Hickory Hills Plant”). The Hickory Hills Plant will process natural gas production from the Arkoma Woodford Basin and is expected to begin operations in the fourth quarter of 2018. Targa will also contribute the 120 MMcf/d cryogenic Tupelo Plant in Coal County, Oklahoma to Centrahoma upon the in-service date of the Hickory Hills Plant.

Eagle Ford Shale Natural Gas Gathering and Processing Joint Venture

In May 2018, Sanchez Midstream Partners LP and we merged our respective 50% interests in the Carnero Gathering and Carnero Processing Joint Ventures, which own the high-pressure Carnero gathering line and Raptor natural gas processing plant, to form an expanded 50/50 joint venture in South Texas (the “Carnero Joint Venture”). In connection with the joint venture merger transactions, the Carnero Joint Venture acquired our 200 MMcf/d Silver Oak II natural gas processing plant located in Bee County Texas, which increased the processing capacity of the joint venture from 260 MMcf/d to 460 MMcf/d. Additional enhancements to the prior joint ventures include dedication of over 315,000 additional gross acres in the Western Eagle Ford, operated by Sanchez Energy Corporation, under a new long-term firm gas gathering and processing agreement. Including the approximately 105,000 Catarina acreage, the joint venture now has over 420,000 gross acres dedicated long term. We operate the gas gathering and processing facilities in the joint venture.

Downstream Segment Expansion

Whistler Pipeline

In August 2018, we announced, along with NextEra Energy Pipeline Holdings, LLC (“NextEra”), WhiteWater Midstream, LLC, and MPLX (collectively, the “Whistler participants”), the execution of a letter of intent for the joint development of the Whistler Pipeline (“Whistler”) which would provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. Whistler is designed to transport approximately 2.0 Bcf/d of natural gas from the Waha hub to Agua Dulce, TX, with an additional segment continuing from Agua Dulce to Wharton County, TX. Supply for Whistler would be sourced from multiple upstream connections in both the Midland and Delaware basins, including direct connections to our plants and the Agua Blanca pipeline. Whistler would be supported by collective commitments in excess of 1.5 Bcf/d from the Whistler participants and their respective producer customers, and would be constructed by NextEra. Targa would operate the pipeline, which is scheduled to begin operation in the fourth quarter of 2020, pending the completion of definitive agreements, final investment decisions by the Whistler participants, and regulatory approvals.

Grand Prix NGL Pipeline

In May 2017, we announced plans to construct a new common carrier NGL pipeline. The NGL pipeline (“Grand Prix”) will transport volumes from the Permian Basin and North Texas to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. Grand Prix will be supported by our volumes and other third-party customer commitments, and is expected to be fully in service in the second quarter of 2019.

In September 2017, we sold a 25% interest in our consolidated subsidiary, Grand Prix Pipeline LLC (the "Grand Prix Joint Venture"), which owns the portion of Grand Prix extending from the Permian Basin to Mont Belvieu, Texas, to funds managed by Blackstone Energy Partners (“Blackstone”). We are the operator and construction manager of Grand Prix.

Concurrent with the sale of the minority interest in the Grand Prix Joint Venture to Blackstone, we and EagleClaw Midstream Ventures, LLC ("EagleClaw"), a Blackstone portfolio company, executed a long-term Raw Product Purchase Agreement whereby EagleClaw has dedicated and committed significant NGLs associated with EagleClaw's natural gas volumes produced or processed in the Delaware Basin.

Grand Prix NGL Pipeline Extension into Oklahoma

In March 2018, we announced an extension of Grand Prix into southern Oklahoma. The pipeline expansion is supported by long-term commitments for both transportation and fractionation services from our existing and future processing plants in the Arkoma area in our SouthOK system and from third-party commitments, including a long-term commitment for transportation and fractionation with Valiant Midstream, LLC. The extension of Grand Prix into southern Oklahoma is not part of the Grand Prix Joint Venture.

The capacity of the 24-inch diameter pipeline segment from the Permian Basin will be approximately 300 MBbl/d, expandable to 550 MBbl/d. The pipeline segment from the Permian Basin will be connected to a 30-inch diameter pipeline segment in North Texas, where Permian, North Texas and Oklahoma volumes will be connected to Mont Belvieu, and will have capacity of approximately 450 MBbl/d, expandable to 950 MBbl/d. The capacity from southern Oklahoma to North Texas will vary based on telescoping pipe size.

Grand Prix economics related to volumes flowing on the pipeline from the Permian Basin to Mont Belvieu are included in the Blackstone and Grand Prix DevCo joint venture arrangements, while the economics related to volumes flowing from North Texas and southern Oklahoma to Mont Belvieu accrue solely to Targa’s benefit.

Total growth capital spending on Grand Prix, including the extension into southern Oklahoma, is now estimated to be approximately $1.7 billion, with our portion of growth capital spending estimated to be approximately $1.1 billion. We expect that our portion of growth capital spending in 2018 will be approximately $900 million. The vast majority of the pipe for Grand Prix has already been purchased.

Fractionation Expansion

In February 2018, we announced plans to construct a new 100 MBbl/d fractionation train in Mont Belvieu, Texas (“Train 6”), which is expected to begin operations in the first quarter of 2019. The total cost of the fractionation train and related infrastructure is expected to be approximately $350 million.

Gulf Coast Express Pipeline

In December 2017, we entered into definitive joint venture agreements with Kinder Morgan Texas Pipeline LLC (“KMTP”) and DCP Midstream Partners, LP (“DCP”) with respect to the joint development of the Gulf Coast Express Pipeline (“GCX”), a natural gas pipeline from the Waha hub to Agua Dulce, Texas. The pipeline will provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. We and DCP each own a 25% interest, and KMTP owns a 50% interest in GCX. Shipper Apache Corporation has an option to purchase up to a 15% equity stake from KMTP. KMTP will serve as the construction manager and operator of GCX. We have committed significant volumes to GCX. In addition, Pioneer Natural Resources Company, a joint owner in our WestTX Permian Basin system, has committed volumes to the project. GCX is designed to transport up to 1.98 Bcf/d of natural gas and the total cost of the project is estimated to be approximately $1.75 billion. GCX is expected to be in service in the fourth quarter of 2019.

Development Joint Ventures

In February 2018, we also announced the formation of three development joint ventures (the “DevCo JVs”) with investment vehicles affiliated with Stonepeak Infrastructure Partners (“Stonepeak”). Stonepeak owns an 80% interest in both the GCX DevCo JV, which owns our 25% interest in GCX, and the Train 6 DevCo JV, which owns a 100% interest in certain assets associated with Train 6. Stonepeak owns a 95% interest in the Grand Prix DevCo JV, which owns a 20% interest in the Grand Prix Joint Venture. We hold the remaining interest of each DevCo JV, as well as control the management, construction and operation of Grand Prix and the fractionation train. The Train 6 DevCo JV will fund the fractionation train while we will fund 100% of the required brine, storage and other infrastructure that will support the fractionation train’s operations.

Stonepeak committed a maximum of approximately $960 million of capital to the DevCo JVs, including an initial contribution of approximately $190 million that was distributed to the Partnership to reimburse it for a portion of capital spent to date.

For a four-year period beginning on the earlier of the date that all three projects have commenced commercial operations or January 1, 2020, Targa has the option to acquire all or part of Stonepeak's interests in the DevCo JVs. Targa may acquire up to 50% of Stonepeak's invested capital in multiple increments with a minimum of $100 million, and Stonepeak's remaining 50% interest in a single final purchase. The purchase price payable for such partial or full interests would be based on a predetermined fixed return or multiple on invested capital, including distributions received by Stonepeak from the DevCo JVs.

Channelview Splitter

On December 27, 2015, we and Noble Americas Corp., then an affiliate of Noble Group Ltd., entered into a long-term, fee-based agreement (the "Splitter Agreement") under which we will build and operate a 35,000 Bbl/d crude oil and condensate splitter at our Channelview Terminal on the Houston Ship Channel (the "Channelview Splitter"). The Channelview Splitter will have the capability to split approximately 35,000 Bbl/d 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. In January 2018, Vitol US Holding Co. acquired Noble Americas Corp.

The Channelview Splitter is expected to be substantially completed in the late third quarter or early fourth quarter of 2018, and has an estimated total cost of approximately $140 million. The first and second annual payments due under the Splitter Agreement were received in 2016 and 2017 and are reflected in deferred revenue as a component of other long-term liabilities on our Consolidated Balance Sheet.

Completed and Potential Asset Sales

During the second quarter of 2018, we sold our inland marine barge business to a third party for approximately $69.3 million. We continue to own and operate two ocean-going barges.

We have engaged an independent investment banking advisory firm to evaluate the potential divestiture of our Downstream Petroleum Logistics business, which includes terminals in Baltimore, MD; Tacoma, WA; and our Channelview Splitter and terminal in Channelview, TX. The potential divestiture is predicated on third party valuations adequately capturing our forward growth expectations for the assets.

2018 Financing Activities

During the six months ended June 30, 2018, we sold 4,405,867 shares of common stock under the December 2016 EDA, resulting in net proceeds of $214.8 million, and 3,274,128 shares of common stock under the May 2017 EDA, receiving net proceeds of $154.8 million.

In April 2018, the Partnership issued $1.0 billion aggregate principal amount of 5 % senior notes due 2026 (the "5 % Senior Notes due 2026"). The Partnership used the net proceeds of $991.9 million after costs from this offering to repay borrowings under its credit facilities and for general partnership purposes.

TRC Revolver Amendment

In June 2018, we entered into an agreement to amend the TRC Revolver to extend the maturity date from February 2020 to June 2023. The available commitments of $670.0 million and our ability to request additional commitments of $200.0 million remained unchanged. The TRC Revolver continues to bear interest costs that are dependent on the ratio of non-Partnership consolidated funded indebtedness to consolidated adjusted EBITDA, as defined in the TRC credit agreement, and the covenants remained substantially the same.

TRP Revolver Amendment

In June 2018, the Partnership entered into an agreement to amend and restate the TRP Revolver, which extended the maturity date from October 2020 to June 2023, increased available commitments from $1.6 billion to $2.2 billion and lowered the applicable margin range and commitment fee range used in the calculation of interest. The Partnership's ability to request additional commitments of $500.0 million remained unchanged.

The TRP Revolver bears interest, at the Partnership's option, either at the base rate or the Eurodollar rate. The base rate is equal to the highest of: (i) Bank of America's prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin (a) before the collateral release date, ranging from 0.25% to 1.25% dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA and (b) upon and after the collateral release date, ranging from 0.125% to 0.75% dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings. The Eurodollar rate is equal to LIBOR rate plus an applicable margin (i) before the collateral release date, ranging from 1.25% to 2.25% dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA and (ii) upon and after the collateral release date, ranging from 1.125% to 1.75% dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings.

The Partnership is required to pay a commitment fee equal to an applicable rate ranging from (a) before the collateral release date, 0.25% to 0.375% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA) and (b) upon and after the collateral release date, 0.125% to 0.35% (dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings) times the actual daily average unused portion of the TRP Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable rate ranging plus an applicable margin (i) before the collateral release date, ranging from 1.25% to 2.25% dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA and (ii) upon and after the collateral release date, ranging from 1.125% to 1.75% dependent on the Partnership's non-credit-enhanced senior unsecured long-term debt ratings. The TRP Revolver's covenants remained substantially the same.

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 contracts. Our growing fee-related capital expenditures for pipelines, expansion of our downstream facilities, as well as third-party acquisitions of businesses and assets, will continue to increase the number of our contracts 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. Nevertheless, a change in unit fees due to market dynamics does affect profitability.

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, connected by third-party transportation and in the future through our Grand Prix pipeline, to our Downstream Business fractionation facilities and at times to our export 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, 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 fees 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 fees (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 our equity volumes 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) attributable to TRC before interest, income taxes, depreciation and amortization, and other items that we believe should be adjusted consistent with our core operating performance. The adjusting items are detailed in the Adjusted EBITDA reconciliation table and its footnotes. 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,	
	2018	2017	2018	2017
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:				
Net income (loss) attributable to TRC	$ 109.1	$ 57.6	$ 132.0	$ (61.7)
Net income (loss) attributable to noncontrolling interests	12.0	13.0	28.0	21.8
Net income (loss)	121.1	70.6	160.0	(39.9)
Depreciation and amortization expense	202.6	203.4	400.7	394.6
General and administrative expense	57.0	51.0	113.8	99.6
Interest (income) expense, net	62.0	62.1	46.0	125.1
Income tax expense (benefit)	32.8	(106.0)	41.6	(34.9)
(Gain) loss on sale or disposition of assets	(46.7)	0.1	(46.8)	16.2
(Gain) loss from financing activities	2.0	10.7	2.0	16.5
Other, net	(62.2)	—	(7.2)	21.1
Operating margin	368.6	291.9	710.1	598.3
Operating expenses	170.5	155.2	343.7	307.2
Gross margin	$ 539.1	$ 447.1	$ 1,053.8	$ 905.5

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In millions)			
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow				
Net income (loss) attributable to TRC	$ 109.1	$ 57.6	$ 132.0	$ (61.7)
Income attributable to TRP preferred limited partners	2.8	2.8	5.6	5.6
Interest (income) expense, net (1)	62.0	62.1	46.0	125.1
Income tax expense (benefit)	32.8	(106.0)	41.6	(34.9)
Depreciation and amortization expense	202.6	203.4	400.7	394.6
(Gain) loss on sale or disposition of assets	(46.7)	0.1	(46.8)	16.2
(Gain) loss from financing activities (2)	2.0	10.7	2.0	16.5
(Earnings) loss from unconsolidated affiliates	(1.9)	4.2	(3.4)	16.8
Distributions from unconsolidated affiliates and preferred partner interests, net	7.0	6.2	13.9	10.4
Change in contingent consideration included in Other expense	(60.6)	(2.1)	(4.5)	1.2
Compensation on equity grants	13.7	10.7	26.9	21.5
Transaction costs related to business acquisitions	—	0.1	—	5.2
Splitter Agreement (3)	10.8	10.8	21.5	21.5
Risk management activities (4)	(0.6)	1.6	9.1	5.2

Noncontrolling interests adjustments (5)	(7.0)	(4.3)	(12.1)	(8.6)
TRC Adjusted EBITDA	$ 326.0	$ 257.9	$ 632.5	$ 534.6
Distributions to TRP preferred limited partners	(2.8)	(2.8)	(5.6)	(5.6)
Splitter Agreement (3)	(10.8)	(10.8)	(21.5)	(21.5)
Interest expense on debt obligations (6)	(63.1)	(56.6)	(118.0)	(115.5)
Cash tax (expense) benefit (7)	—	31.4	—	46.7
Maintenance capital expenditures	(24.8)	(23.3)	(47.1)	(49.0)
Noncontrolling interests adjustments of maintenance capital expenditures	0.6	0.2	1.1	0.5
Distributable Cash Flow	$ 225.1	$ 196.0	$ 441.4	$ 390.2

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(1) Includes the change in estimated redemption value of the mandatorily redeemable preferred interests.

(2) Gains or losses on debt repurchases, amendments, exchanges or early debt extinguishments.

(3) 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.

(4) Risk management activities related to derivative instruments including the cash impact of hedges acquired in the 2015 mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. The cash impact of the acquired hedges ended in December 2017.

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

(6) Excludes amortization in interest expense.

(7) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which is recognized over the periods between the third quarter 2016 of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before the fourth quarter of 2017, was received in the second quarter of 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,				Six Months Ended June 30,			
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
	(In millions, except operating statistics and price amounts)							
Revenues								
Sales of commodities	$ 2,154.1	$ 1,623.8	$ 530.3	33 %	$ 4,327.4	$ 3,481.7	$ 845.7	24 %
Fees from midstream services	290.3	243.9	46.4	19 %	572.6	498.6	74.0	15 %
Total revenues	2,444.4	1,867.7	576.7	31 %	4,900.0	3,980.3	919.7	23 %
Product purchases	1,905.3	1,420.6	484.7	34 %	3,846.2	3,074.8	771.4	25 %
Gross margin (1)	539.1	447.1	92.0	21 %	1,053.8	905.5	148.3	16 %
Operating expenses	170.5	155.2	15.3	10 %	343.7	307.2	36.5	12 %
Operating margin (1)	368.6	291.9	76.7	26 %	710.1	598.3	111.8	19 %
Depreciation and amortization expense	202.6	203.4	(0.8)	—	400.7	394.6	6.1	2 %
General and administrative expense	57.0	51.0	6.0	12 %	113.8	99.6	14.2	14 %
Other operating (income) expense	(46.4)	0.3	(46.7)	NM	(46.1)	16.5	(62.6)	NM
Income (loss) from operations	155.4	37.2	118.2	NM	241.7	87.6	154.1	176 %
Interest income (expense), net	(62.0)	(62.1)	0.1	—	(46.0)	(125.1)	79.1	63 %
Equity earnings (loss)	1.9	(4.2)	6.1	145 %	3.4	(16.8)	20.2	120 %
Gain (loss) from financing activities	(2.0)	(10.7)	8.7	81 %	(2.0)	(16.5)	14.5	88 %
Change in contingent considerations	60.6	2.1	58.5	NM	4.5	(1.2)	5.7	NM
Other income (expense), net	—	2.3	(2.3)	(100%)	—	(2.8)	2.8	100 %
Income tax (expense) benefit	(32.8)	106.0	(138.8)	(131%)	(41.6)	34.9	(76.5)	(219%)
Net income (loss)	121.1	70.6	50.5	72 %	160.0	(39.9)	199.9	NM
Less: Net income (loss) attributable to noncontrolling interests	12.0	13.0	(1.0)	(8 %)	28.0	21.8	6.2	28 %
Net income (loss) attributable to Targa Resources Corp.	109.1	57.6	51.5	89 %	132.0	(61.7)	193.7	NM
Dividends on Series A Preferred Stock	22.9	22.9	—	—	45.8	45.8	—	—
Deemed dividends on Series A Preferred Stock	7.2	6.3	0.9	14 %	14.1	12.5	1.6	13 %
	$ 79.0	$ 28.4	$ 50.6	178 %	$ 72.1	$ (120.0)	$ 192.1	160 %

Net income (loss) attributable to common shareholders								
Financial data:								
Adjusted EBITDA (1)	$ 326.0	$ 257.9	$ 68.1	26 %	$ 632.5	$ 534.6	$ 97.9	18 %
Distributable cash flow (1)	225.1	196.0	29.1	15 %	441.4	390.2	51.2	13 %
Capital expenditures (2)	734.8	434.5	300.3	69 %	1,292.7	609.1	683.6	112 %
Business acquisition (3)	—	—	—	—	—	987.1	(987.1)	(100%)

(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) Capital expenditures, net of contributions from noncontrolling interest, were $1,080.0 million and $591.9 million for the six months ended June 30, 2018 and 2017.

(3) Includes the $416.3 million acquisition date fair value of the potential earn-out payments.

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, 2018 Compared to Three Months Ended June 30, 2017

The increase in commodity sales reflects higher NGL and condensate prices ($413.3 million) and increased NGL, natural gas, petroleum and condensate volumes ($384.8 million), partially offset by lower natural gas prices ($175.7 million) and the impact of hedges ($15.3 million). Fee-based and other revenues increased primarily due to higher gas processing and crude gathering fees.

The increase in product purchases reflects increased volumes and higher NGL and condensate prices.

The prospective adoption of the revenue recognition accounting standard as set forth in Topic 606 in 2018 resulted in lower commodity sales ($79.9 million) and lower fee revenue ($6.2 million) with a corresponding net reduction in product purchases, resulting in no impact on operating margin or gross margin.

The higher operating margin and gross margin in 2018 reflects increased segment margin results for Gathering and Processing and Logistics and Marketing. Operating expenses increased compared to 2017 primarily due to plant and system expansions in the Permian region and higher compensation and benefits. See “—Results of Operations—By Reportable Segment” for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense was flat as higher depreciation related to our growth investments was offset by lower depreciation for our North Texas system, which was partially impaired in the third quarter of 2017, and lower scheduled amortization of Badlands intangibles.

General and administrative expense increased primarily due to higher compensation and benefits.

Other operating (income) expense in 2018 was comprised primarily of the gain on sale of our inland marine barge business.

Interest income (expense), net was essentially flat as the impact of higher average borrowings was offset by higher capitalized interest and the effect of lower mandatory redeemable preferred interest valuations.

Equity earnings increased in 2018, primarily reflecting increased earnings at Gulf Coast Fractionators LP ("GCF") and commencement of Cayenne operations.

In 2018, we recorded a loss from financing activities of $2.0 million associated with amendments to our revolving credit facilities, which resulted in a write-off of debt issuance costs. In 2017, we recorded a loss from financing activities of $10.7 million on the redemption of the outstanding 6 % Senior Notes.

During 2018, we recorded income of $60.6 million resulting primarily from a decrease in fair value as of June 30, 2018 of the Permian Acquisition contingent consideration liability. The fair value decrease was primarily attributable to lower forecasted volumes for the remainder of the earn-out period, partially offset by a shorter discount period. The underlying forecasted volumes reflect the most recently observed production trends. During 2017, we recorded income of $2.1 million resulting from a decrease in the fair value of the contingent consideration liability from the March 1, 2017 acquisition date to June 30, 2017.

During 2018, we recorded income tax expense, whereas in 2017 we recorded an income tax benefit. In the first and second quarters of 2018, we determined income tax expense (benefit) using the estimated annual effective tax rate. However, in 2017, the application of interim tax accounting rules required us to use the statutory tax rate for the six-month period ended June 30, 2017 versus the estimated annual effective tax rate for the three-month period ending March 31, 2017. As such, the second quarter of 2017 included an income tax benefit of $106.0 million reflecting the difference between (1) an income tax benefit of $34.9 million for the six months ended June 30, 2017 using the statutory tax rate and (2) income tax expense of $71.1 million for the three months ended March 31, 2017 using the estimated annual effective tax rate.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The increase in commodity sales reflects increased NGL, natural gas, petroleum and condensate volumes ($699.7 million) and higher NGL and condensate prices ($627.1 million), partially offset by lower natural gas prices ($262.2 million) and the impact of hedges ($47.3 million). Fee-based and other revenues increased primarily due to higher gas processing and crude gathering fees.

The increase in product purchases reflects increased volumes and higher NGL and condensate prices.

The prospective adoption of the revenue recognition accounting standard as set forth in Topic 606 in 2018 resulted in lower commodity sales ($166.0 million) and lower fee revenue ($12.8 million) with a corresponding net reduction in product purchases, resulting in no impact on operating margin or gross margin.

The higher operating margin and gross margin in 2018 reflects increased segment margin results for Gathering and Processing and Logistics and Marketing. Operating expenses increased compared to 2017 primarily due to plant and system expansions in the Permian region, the inclusion of the Permian Acquisition for six months in 2018 as compared with four months in 2017 and higher compensation and benefits. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in operating margin and gross margin on a segment basis.

Depreciation and amortization expense increased as higher depreciation related to our growth investments was partially offset by lower depreciation for our North Texas system, which was partially impaired in the third quarter of 2017, and lower scheduled amortization of Badlands intangibles.

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

Other operating (income) expense in 2018 was comprised primarily of the gain on sale of our inland marine barge business. In 2017, other operating (income) expense included the first quarter loss due to the reduction in the carrying value of our 100% ownership interest in the Venice Gathering System, in contemplation of its April 2017 sale.

Lower interest income (expense), net in 2018 was primarily due to higher non-cash interest income related to a decrease in the mandatorily redeemable preferred interests liability and higher capitalized interest. These factors more than offset the impact of higher average outstanding borrowings during 2018. The mandatorily redeemable preferred interests liability is revalued quarterly at the estimated redemption value as of the reporting date, and the decrease in 2018 of its estimated redemption value is primarily attributable to the February 2018 amendments to the agreements governing the WestTX and WestOK joint ventures.

Equity earnings increased in 2018, which reflects decreased losses of the T2 Joint Ventures, which in 2017 included a $12.0 million loss provision due to the impairment of our investment in the T2 EF Cogen joint venture, increased earnings at GCF and the commencement of operations at Cayenne.

In 2018, we recorded a loss from financing activities of $2.0 million associated with amendments to our revolving credit facilities, which resulted in a write-off of debt issuance costs. In 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.

During 2018, we recorded income of $4.5 million resulting from the change in the fair value of contingent considerations, substantially all of which was due to the decrease in fair value as of June 30, 2018 of the Permian Acquisition contingent consideration liability described above. During 2017, we recorded expense of $1.1 million resulting from an increase in the fair value of the Permian Acquisition contingent consideration liability from the acquisition date to June 30, 2017.

During 2018, we recorded income tax expense, whereas in 2017 we recorded an income tax benefit. As described above in the quarterly results, we utilized the estimated annual effective tax rate in 2018, whereas in 2017 we used the then statutory rate of 37.3% due to the loss limitation rule under interim period income tax accounting.

Net income attributable to noncontrolling interests was higher in 2018 due to increased earnings at our consolidated Carnero joint venture in South Texas.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Consolidated Operating Margin
	(In millions)				
Three Months Ended:					
June 30, 2018	$ 242.2	$ 129.9	$ (3.5)	$ —	$ 368.6
June 30, 2017	173.5	112.4	6.0	—	291.9
Six Months Ended:					
June 30, 2018	$ 463.3	$ 268.3	$ (21.4)	$ (0.1)	$ 710.1
June 30, 2017	351.1	242.4	4.9	(0.1)	598.3

Gathering and Processing Segment

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
Gross margin	$ 346.9	$ 264.2	$ 82.7	31 %	$ 672.6	$ 527.4	$ 145.2	28 %
Operating expenses	104.7	90.7	14.0	15 %	209.3	176.3	33.0	19 %
Operating margin	$ 242.2	$ 173.5	$ 68.7	40 %	$ 463.3	$ 351.1	$ 112.2	32 %
Operating statistics (1):								
Plant natural gas inlet, MMcf/d (2),(3)								
Permian Midland (4)	1,125.1	867.5	257.6	30 %	1,069.9	830.8	239.1	29 %
Permian Delaware (4)	417.3	378.2	39.1	10 %	413.3	358.2	55.1	15 %
Total Permian	1,542.4	1,245.7	296.7		1,483.2	1,189.0	294.2	
SouthTX	413.5	222.6	190.9	86 %	414.9	197.4	217.5	110%
North Texas	246.1	277.1	(31.0)	(11 %)	240.6	279.8	(39.2)	(14 %)
SouthOK	549.9	479.0	70.9	15 %	539.9	459.8	80.1	17 %
WestOK	348.2	387.4	(39.2)	(10 %)	349.1	390.3	(41.2)	(11 %)
Total Central	1,557.7	1,366.1	191.6		1,544.5	1,327.3	217.2	
Badlands (5)	85.9	52.2	33.7	65 %	79.7	49.1	30.6	62 %
Total Field	3,186.0	2,664.0	522.0		3,107.4	2,565.4	542.0	
Coastal	665.3	741.6	(76.3)	(10 %)	694.6	749.9	(55.3)	(7 %)
Total	3,851.3	3,405.6	445.7	13 %	3,802.0	3,315.3	486.7	15 %
Gross NGL production, MBbl/d (3)								
Permian Midland (4)	151.4	112.8	38.6	34 %	145.9	106.3	39.6	37 %
Permian Delaware (4)	50.3	42.9	7.4	17 %	48.0	40.4	7.6	19 %
Total Permian	201.7	155.7	46.0		193.9	146.7	47.2	
SouthTX	54.5	23.5	31.0	132%	54.3	20.1	34.2	170%
North Texas	28.8	31.1	(2.3)	(7 %)	27.4	31.5	(4.1)	(13 %)
SouthOK	51.1	38.5	12.6	33 %	50.0	39.7	10.3	26 %
WestOK	19.5	23.5	(4.0)	(17 %)	19.5	23.1	(3.6)	(16 %)
Total Central	153.9	116.6	37.3		151.2	114.4	36.8	
Badlands	10.8	7.7	3.1	40 %	10.5	6.6	3.9	59 %
Total Field	366.4	280.0	86.4		355.6	267.7	87.9	
Coastal	38.3	41.2	(2.9)	(7 %)	40.4	37.3	3.1	8 %
Total	404.7	321.2	83.5	26 %	396.0	305.0	91.0	30 %
	139.8	112.5	27.3	24 %	128.8	113.0	15.8	14 %

Crude oil gathered, Badlands, MBbl/d								
Crude oil gathered, Permian, MBbl/d (4)	66.6	28.6	38.0	133%	58.0	18.9	39.1	207%
Natural gas sales, BBtu/d (3)	1,878.1	1,655.2	222.9	13 %	1,823.0	1,601.6	221.4	14 %
NGL sales, MBbl/d	304.1	249.2	54.9	22 %	302.0	238.4	63.6	27 %
Condensate sales, MBbl/d	19.6	12.1	7.5	62 %	17.9	11.4	6.5	57 %
Average realized prices (6):								
Natural gas, $/MMBtu	1.82	2.70	(0.88)	(33 %)	2.09	2.79	(0.70)	(25 %)
NGL, $/gal	0.66	0.46	0.20	43 %	0.63	0.48	0.15	31 %
Condensate, $/Bbl	58.01	42.74	15.27	36 %	58.75	43.79	14.96	34 %

(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 Permian Midland and New Delaware volumes are included within Permian Delaware. 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, 2018 Compared to Three Months Ended June 30, 2017

The increase in gross margin was primarily due to higher Permian, Central and Badlands volumes and higher NGL and condensate prices, partially offset by lower natural gas prices. The increase in Field Gathering and Processing inlet volumes included both areas in the Permian region, SouthTX, SouthOK and Badlands, partially offset by decreases at WestOK and North Texas. NGL production, NGL sales and natural gas sales increased primarily due to higher Field Gathering and Processing inlet volumes and increased NGL recoveries including reduced ethane rejection. Coastal Gathering and Processing had a positive margin impact due to richer gas, increased recoveries and higher NGL prices, despite lower inlet volumes. Total crude oil gathered volumes increased in the Permian region due to higher production from new wells. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to higher production from new wells and system expansions.

The increase in operating expenses was primarily driven by gas plant and system expansions in the Permian region. Operating expenses in other areas were relatively flat.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

The increase in gross margin was primarily due to higher Permian volumes including those associated with the Permian Acquisition in March 2017, higher Central and Badlands volumes and higher NGL and condensate prices, partially offset by lower natural gas prices. The overall increase in Field Gathering and Processing inlet volumes included both areas of the Permian region, SouthTX, SouthOK and Badlands, partially offset by decreases at WestOK and North Texas. NGL production, NGL sales and natural gas sales increased primarily due to higher Field Gathering and Processing inlet volumes and increased NGL recoveries including reduced ethane rejection. Coastal Gathering and Processing had a positive margin impact due to richer gas, increased recoveries and higher NGL prices, partially offset by lower inlet volumes. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition and higher production from new wells and system expansions. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to higher production from new wells and system expansions.

The increase in operating expenses was primarily driven by gas plant and system expansions in the Permian region and the inclusion of the March 2017 Permian Acquisition for the full period of 2018. Operating expenses in other areas were relatively flat.

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, 2018			
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
Permian Midland	1,416.4	Varies (4)	1,125.1	1,125.1
Permian Delaware	417.3	100 %	417.3	417.3
Total Permian	1,833.7		1,542.4	1,542.4
SouthTX	413.5	Varies (5)	296.5	413.5
North Texas	246.1	100 %	246.1	246.1
SouthOK	549.9	Varies (6)	440.1	549.9
WestOK	348.2	100 %	348.2	348.2
Total Central	1,557.7		1,330.9	1,557.7
Badlands (7)	85.9	100 %	85.9	85.9
Total Field	3,477.3		2,959.2	3,186.0
Gross NGL production, MBbl/d (2)				
Permian Midland	191.4	Varies (4)	151.4	151.4
Permian Delaware	50.3	100 %	50.3	50.3
Total Permian	241.7		201.7	201.7
SouthTX	54.5	Varies (5)	37.7	54.5
North Texas	28.8	100 %	28.8	28.8
SouthOK	51.1	Varies (6)	41.4	51.1
WestOK	19.5	100 %	19.5	19.5
Total Central	153.9		127.4	153.9
Badlands	10.8	100 %	10.8	10.8
Total Field	406.4		339.9	366.4

(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, other than Badlands.
(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) Permian Midland includes operations in WestTX, of which we own 73%, and other plants that are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported

financials.

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

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

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

	Three Months Ended June 30, 2017			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
Permian Midland (4)	1,075.2	Varies (5)	867.5	867.5
Permian Delaware (4)	378.2	100 %	378.2	378.2
Total Permian	1,453.4		1,245.7	1,245.7
SouthTX	222.6	Varies (6)	212.4	222.6
North Texas	277.1	100 %	277.1	277.1
SouthOK	479.0	Varies (7)	366.1	479.0
WestOK	387.4	100 %	387.4	387.4
Total Central	1,366.1		1,243.0	1,366.1
Badlands (8)	52.2	100 %	52.2	52.2
Total Field	2,871.7		2,540.9	2,664.0
Gross NGL production, MBbl/d (2)				
Permian Midland (4)	140.8	Varies (5)	112.8	112.8
Permian Delaware (4)	42.9	100 %	42.9	42.9
Total Permian	183.7		155.7	155.7
SouthTX	23.5	Varies (6)	22.6	23.5
North Texas	31.1	100 %	31.1	31.1
SouthOK	38.5	Varies (7)	31.4	38.5
WestOK	23.5	100 %	23.5	23.5
Total Central	116.6		108.6	116.6
Badlands	7.7	100 %	7.7	7.7
Total Field	308.0		272.0	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, other than Badlands.
(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 Permian Midland and New Delaware volumes are included within Permian Delaware.
(5) Permian Midland includes operations in WestTX, of which we own 73%, and other plants that are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(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 owned a 100% interest until it was contributed to the Carnero Joint Venture. The Carnero Joint Venture is 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 that 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,			
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
	(In millions)							
Gross margin	$ 196.9	$ 176.9	$ 20.0	11 %	$ 403.7	$ 373.2	$ 30.5	8 %
Operating expenses	67.0	64.5	2.5	4 %	135.4	130.8	4.6	4 %
Operating margin	$ 129.9	$ 112.4	$ 17.5	16 %	$ 268.3	$ 242.4	$ 25.9	11 %
Operating statistics MBbl/d (1):								
Fractionation volumes (2)(3)	412.2	338.5	73.7	22 %	401.0	321.8	79.2	25 %
LSNG treating volumes (2)	33.7	33.3	0.4	1 %	32.0	33.9	(1.9)	(6 %)
Benzene treating volumes (2)	—	22.1	(22.1)	(100 %)	6.6	22.8	(16.2)	(71 %)
Export volumes (4)	190.3	155.3	35.0	23 %	196.1	186.2	9.9	5 %
NGL sales	509.3	439.4	69.9	16 %	512.0	470.5	41.5	9 %
Average realized prices:								
NGL realized price, $/gal	$ 0.76	$ 0.58	$ 0.18	31 %	$ 0.76	$ 0.62	$ 0.14	23 %

(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 that 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, 2018 Compared to Three Months Ended June 30, 2017

Logistics and Marketing gross margin increased due to higher fractionation margin, higher marketing gains, higher terminaling and storage throughput, higher domestic marketing margin and higher LPG export margin, partially offset by slightly lower treating margin. Fractionation margin increased due to higher supply volume, partially offset by lower system product gains. Fractionation margin was partially impacted by the variable effects of fuel and power that are largely reflected in operating expenses (see footnote (2) above). Marketing gains increased primarily due to optimization of gas transportation arrangements. Domestic marketing margin increased due to higher terminal margins and volumes. LPG export margin increased due to higher volumes and fees, partially offset by the absence of cancellation fees in 2018. Treating margin decreased due to lower benzene treating volumes which were zero in the second quarter 2018; however, we continue to receive take-or-pay payments related to the contract we have in place through 2018.

Operating expenses increased due to higher compensation and benefits and higher taxes, partially offset by lower fuel and power costs that are largely passed through.

Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Logistics and Marketing gross margin increased due to higher fractionation margin, higher marketing gains, higher terminaling and storage throughput and higher domestic marketing margin, partially offset by lower LPG export margin and lower treating margin. Fractionation margin increased due to higher supply volume and higher system product gains. Fractionation margin was partially impacted by the variable effects of fuel and power that are largely reflected in operating expenses (see footnote (2) above). Marketing gains increased primarily due to optimization of liquids arrangements. Domestic marketing margin increased due to higher terminal margins and volumes. LPG export margin decreased due to slightly lower fees and the absence of cancellation fees in 2018, partially offset by higher volumes. Treating margin decreased primarily due to lower benzene treating volumes which were zero in the second quarter 2018; however, we continue to receive take-or-pay payments related to the contract we have in place through 2018.

Operating expenses increased due to higher compensation and benefits and higher taxes, partially offset by lower maintenance costs, and lower fuel and power costs that are largely passed through.

Other

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	2017	2018 vs. 2017	2018	2017	2018 vs. 2017
	(In millions)					
Gross margin	$(3.5)	$6.0	$(9.5)	$(21.4)	$4.9	$(26.3)
Operating margin	$(3.5)	$6.0	$(9.5)	$(21.4)	$4.9	$(26.3)

Other contains the results 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, 2018			Three Months Ended June 30, 2017		
	(In millions, except volumetric data and price amounts)					
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	17.0	$ 1.01	$ 17.1	15.5	$ 0.16	$ 2.5
NGL (MMgal)	94.8	(0.15)	(14.0)	59.4	0.01	0.8
Crude oil (MBbl)	0.5	(14.21)	(7.2)	0.3	6.93	2.3
Non-hedge accounting (2)			0.6			0.4
Ineffectiveness (3)			—			—
			$ (3.5)			$ 6.0

	Six Months Ended June 30, 2018			Six Months Ended June 30, 2017		
	(In millions, except volumetric data and price amounts)					
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	32.8	$ 0.70	$ 22.9	26.0	$ 0.09	$ 2.6
NGL (MMgal)	187.3	(0.12)	(23.4)	102.7	(0.01)	(1.1)
Crude oil (MBbl)	1.0	(11.72)	(11.8)	0.6	6.29	3.5
Non-hedge accounting (2)			(9.1)			(0.3)
Ineffectiveness (3)			—			0.2
			$ (21.4)			$ 4.9

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.
(3) Effective upon the adoption of ASU 2017-12 on January 1, 2018, we are no longer required to recognize ineffectiveness through operating margin. Previously, ineffectiveness primarily related to certain crude hedging contracts and certain acquired hedges of Targa Pipeline Partners, L.P. ("TPL") that did 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. The final settlement was received in December 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, 2018, we had $281.6 million of “Cash and cash equivalents,” on our Consolidated Balance Sheets. 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.

Our liquidity and capital resources are 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 to pay 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.

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. We may supplement these sources of liquidity with proceeds from potential asset sales and/or joint ventures. 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 August 6, 2018, was:

	August 6, 2018 (In millions)		
			Consolidated
	TRC	TRP	Total
Cash on hand	$ 15.1	$ 439.1	$ 454.2
Total availability under the TRC Revolver	670.0	—	670.0
Total availability under the TRP Revolver	—	2,200.0	2,200.0
Total availability under the Securitization Facility	—	350.0	350.0
	685.1	2,989.1	3,674.2
Less: Outstanding borrowings under the TRC Revolver	(160.0)	—	(160.0)
Outstanding borrowings under the TRP Revolver	—	(80.0)	(80.0)
Outstanding borrowings under the Securitization Facility	—	(350.0)	(350.0)
Outstanding letters of credit under the TRP Revolver	—	(71.5)	(71.5)
Total liquidity	$ 525.1	$ 2,487.6	$ 3,012.7

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 June 29, 2023.
- 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 June 29, 2023.

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 tied to commodity sales and purchases are relatively balanced, with receivables from NGL customers being offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (i) our cash position; (ii) liquids inventory levels and valuation, which we closely manage; (iii) changes in the fair value of the current portion of derivative contracts; (iv) monthly swings in borrowings under the Securitization Facility; and (v) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

Working capital as of June 30, 2018 decreased $175.1 million compared to December 31, 2017. Our working capital, exclusive of current debt obligations and reclassifications from other long term liabilities, decreased $32.7 million from December 31, 2017 to June 30, 2018. The major items contributing to this decrease in working capital were increases in accounts payable and accruals especially those related to our Grand Prix and Train 6 projects, a reduction in inventories primarily attributable to a decrease in prices and volumes in storage, and a decrease in net risk management position due to changes in forward prices of commodities, partially offset by higher cash balances. Working capital as of June 30, 2018 was also impacted by a $312.4 million decrease due to the reclassification of the May 2019 estimated contingent consideration payment from noncurrent liabilities and a $170.0 million increase due to lower borrowings under our Securitization Facility.

Based on our anticipated levels of operations and absent any disruptive events, we believe that our internally generated cash flow, borrowings available under the TRC Revolver, the TRP Revolver and the Securitization Facility and proceeds from debt and equity offerings, as well as joint ventures and/or potential asset sales, 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

In February 2018, we formed three DevCo JVs with Stonepeak, which committed a maximum of approximately $960 million of capital to the DevCo JVs. For the six months ended June 30, 2018, total contributions from Stonepeak were $337.3 million, which are included in noncontrolling interests.

During 2018, we issued 4,405,867 shares of common stock under the December 2016 EDA, receiving net proceeds of $214.8 million. We also sold 3,274,128 shares of common stock under our May 2017 EDA, receiving net proceeds of $154.8 million. As of August 1, 2018, we have $107.7 million remaining under the December 2016 EDA and $594.0 million remaining under the May 2017 EDA.

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, 2018 and December 31, 2017, the aggregate principal amount outstanding of our senior notes and other various long-term debt obligations (excluding current maturities) was $5,427.6 million and $4,732.6 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 9 – 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, the TRP Revolver and the Securitization Facility. 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, 2018, we did not have any interest rate hedges.

In April 2018, the Partnership issued $1.0 billion aggregate principal amount of the 5 % Senior Notes due 2026. The Partnership used the net proceeds of $991.9 million after costs from this offering to repay borrowings under its credit facilities and for general partnership purposes.

In June 2018, we entered into an agreement to amend the TRC Revolver which extended the maturity date from February 2020 to June 2023. The available commitments of $670.0 million and our ability to request additional commitments of $200.0 million remained unchanged. The TRC Revolver continues to bear interest costs that are dependent on our ratio of non-Partnership consolidated funded indebtedness to consolidated adjusted EBITDA and the covenants remained substantially the same.

In June 2018, the Partnership entered into an agreement to amend and restate the TRP Revolver which extended the maturity date from October 2020 to June 2023 and increased available commitments from $1.6 billion to $2.2 billion. The Partnership's ability to request additional commitments of $500.0 million remained unchanged. The TRP Revolver continues to bear interest costs that are dependent on the ratio of the Partnership's consolidated funded indebtedness to consolidated adjusted EBITDA and the covenants remained substantially the same.

To date, our and our subsidiaries' debt balances have not adversely affected our operations, ability to grow or ability to repay or refinance indebtedness. For additional information about our debt-related transactions, see Note 9 - 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, 2018, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

Six Months Ended June 30,		
		2018 vs.
2018	2017	2017
(In millions)		
$543.7	$464.5	$79.2

The primary drivers of cash flows from operating activities are (i) the collection of cash from customers from the sale of NGLs, natural gas and other petroleum commodities, as well as fees for gas processing, crude gathering, export, fractionation, terminaling, storage and transportation, (ii) the payment of amounts related to the purchases of NGLs and natural gas, and (iii) the payment of other expenses, primarily field operating costs, general and administrative expense and interest expense. In addition, we use derivative instruments to manage our exposure to commodity price risk. Changes in the prices of the commodities we hedge impact our derivative settlements as well as our margin deposit requirements on unsettled futures contracts.

Net cash provided by operations increased from 2017 to 2018 primarily due to the impact of higher commodity prices and volumes, higher capitalized interest, increases in distributions from unconsolidated affiliates and lower acquisition costs, partially offset by a tax refund received in 2017. The increase in commodity prices and volumes resulted in higher cash collections from customers, partially offset by higher product purchases and an increase in cash payments related to our derivative contracts. Higher capitalized interest resulted in lower interest payments included in operating cash flows. Increases in earnings from unconsolidated affiliates contributed to higher distributions. In 2017, we paid acquisition costs related to a business acquisition, which did not recur in 2018.

Cash Flows from Investing Activities

Six Months Ended June 30,		
		2018 vs.
2018	2017	2017

(In millions)		
$(1,236.9)	$(1,108.6)	$(128.3)

Cash used in investing activities increased in 2018 compared to 2017, primarily due to increased outlays for property, plant and equipment and contributions to unconsolidated affiliates, partially offset by lower outlays for business acquisitions and higher proceeds from the sale of assets.

Our capital expenditures for property, plant and equipment increased $634.9 million in 2018 primarily related to a large number of capital projects, and our contributions to unconsolidated affiliates increased $142.0 million primarily due to the construction activities of GCX and LM4.

We have made no cash payment for business acquisitions in 2018, whereas in 2017 we paid $570.8 million for the initial cash portion of the Permian Acquisition. In 2018, we received proceeds of $69.3 million from the sale of our inland marine barge business.

Cash Flows from Financing Activities

	Six Months Ended June 30,	
	2018	2017
Source of Financing Activities, net	(In millions)	
Debt, including financing costs	$506.2	$(462.6)
Contributions from noncontrolling interests	447.1	16.5
Equity offerings, net of financing costs	369.5	1,558.5
Dividends and distributions	(450.9)	(408.6)
Other	(34.3)	(34.5)
Net cash provided by (used in) financing activities	$837.6	$669.3

In 2018, we realized a net source of cash from financing activities primarily due to a net increase of debt outstanding and contributions from noncontrolling interests, partially offset by payments of dividends and distributions. The issuance of 5 % Senior Notes due 2026, partially offset by repayments of outstanding borrowings under our credit facilities contributed to the net increase of debt outstanding. The contributions from noncontrolling interests were primarily from Stonepeak and Blackstone to fund growth projects.

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 EDA. 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.

Common Dividends

The following table details the dividends on common stock declared and/or paid by us for the six months ended June 30, 2018:

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)	Dividends Declared per Share of Common Stock
(In millions, except per share amounts)					
June 30, 2018	August 15, 2018	$ 208.9	$ 205.2	$ 3.7	$ 0.91000
March 31, 2018	May 16, 2018	203.1	199.7	3.4	0.91000
December 31, 2017	February 15, 2018	202.4	199.1	3.3	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.

Cash dividends of $45.8 million were paid to holders of the Series A Preferred during the six months ended June 30, 2018. As of June 30, 2018, cash dividends accrued for our Series A Preferred were $22.9 million, which will be paid on August 14, 2018.

Capital Requirements

Our capital requirements relate to capital expenditures, which are classified as growth capital expenditures, business acquisitions, and maintenance expenditures. Growth 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,	
	2018	2017
	(In millions)	
Capital requirements:		
Consideration for business acquisition	$—	$987.1
Contingent consideration (1)	—	(416.3)
Cash outlay for business acquisition, net of cash acquired	—	570.8
Growth (2)	1,245.6	560.0
Maintenance (2)	47.1	49.1
Gross capital expenditures	1,292.7	609.1
Transfers of capital expenditures to investment in unconsolidated affiliates	16.0	—
Transfers from materials and supplies inventory to property, plant and equipment	(1.0)	(1.5)
Change in capital project payables and accruals	(145.2)	(80.0)
Cash outlays for capital projects	1,162.5	527.6
Total capital outlays	$1,162.5	$1,098.4

(1) See Note 4 – Newly-Formed Joint Ventures and Acquisitions of the “Consolidated Financial Statements.” Represents the fair value of contingent consideration at the acquisition date.
(2) Growth capital expenditures, net of contributions from noncontrolling interests, were $1,034.0 million and $543.4 million for the six months ended June 30, 2018 and 2017. Maintenance capital expenditures, net of contributions from noncontrolling interests, were $46.0 million and $48.5 million for the six months ended June 30, 2018 and 2017.

We currently estimate that we will invest at least $2,180 million in net growth capital expenditures (exclusive of outlays for business acquisitions) and contributions to investments in unconsolidated affiliates for announced projects in 2018. 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 growth capital expenditures may vary significantly based on investment opportunities. We expect that 2018 net maintenance capital expenditures will be approximately $120 million.

Total growth capital expenditures increased for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017, primarily due to spending related to Grand Prix, additional processing plants and associated infrastructure in the Permian Basin, SouthOK and Badlands, and construction of Train 6. Total maintenance capital expenditures were relatively flat for the comparable periods.

Off-Balance Sheet Arrangements

As of June 30, 2018, there were $50.3 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 2021. 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, NGLs and crude oil 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, 2018, 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 hedges are 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 \$(9.9) million and \$5.4 million during the three months ended June 30, 2018 and 2017, and \$(48.7) million and \$(1.3) million during the six months ended June 30, 2018 and 2017, 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 $38.2 million at December 31, 2017 to a net liability position of $62.8 million at June 30, 2018. The fixed prices we currently expect to receive on derivative contracts are below the aggregate forward prices for commodities related to those contracts, creating this net liability position.

As of June 30, 2018, we had the following derivative instruments that will settle during the years shown below:

Natural GAS

Instrument Type	Index	Price $/MMBtu	MMBtu/d 2018	2019	2020	2021	Fair Value (In millions)
Gathering & Processing							
Swap	IF-Waha	2.6470	93,600	-	-	-	$ 17.4
Swap	IF-Waha	2.6327	-	65,383	-	-	27.6
			93,600	65,383	-	-	
Swap	IF-PB	2.4802	45,900	-	-	-	7.6
Swap	IF-PB	2.3700	-	35,000	-	-	12.0
			45,900	35,000	-	-	
Swap	IF-PEPL	2.5960	31,370	-	-	-	1.9
Swap	IF-PEPL	2.5333	-	31,370	-	-	4.9
Swap	IF-PEPL	2.0700	-	-	15,500	-	(0.1)
Swap	IF-PEPL	2.4750	-	-	-	3,822	0.2
			31,370	31,370	15,500	3,822	
Gathering & Processing total			170,870	131,753	15,500	3,822	$ 71.5
Other (1)							
Swap	NG-NYMEX	2.9000	(130)	-	-	-	$ 0.0
Swap	NG-NYMEX	2.8367	-	(247)	-	-	(0.0)
			(130)	(247)	-	-	
Basis Swap	Various	Various	135,842	97,377	30,417	16,658	(11.6)
Other total			135,712	97,130	30,417	16,658	$ (11.6)
							$ 59.9

(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 2018	2019	2020	2021	Fair Value (In millions)
Gathering & Processing								
Swap	C2-OPIS-MB	0.2822		5,720	-	-	-	(1.2)
Swap	C2-OPIS-MB	0.2928		-	5,270	-	-	0.9
Swap	C2-OPIS-MB	0.2994		-	-	2,237	-	0.2
Swap	C2-OPIS-MB	0.3010		-	-	-	163	(0.0)
Total				5,720	5,270	2,237	163	
Swap	C3-OPIS-MB	0.7124		9,870	-	-	-	(17.4)
Swap	C3-OPIS-MB	0.6654		-	7,240	-	-	(15.2)
Swap	C3-OPIS-MB	0.6349		-	-	3,150	-	(5.3)
Swap	C3-OPIS-MB	0.6640		-	-	-	217	(0.3)
Total				9,870	7,240	3,150	217	
Swap	IC4-OPIS-MB	0.8824		1,320	-	-	-	(2.4)
Swap	IC4-OPIS-MB	0.8188		-	780	-	-	(1.3)
Swap	IC4-OPIS-MB	0.7343		-	-	430	-	(0.9)
Swap	IC4-OPIS-MB	0.7640		-	-	-	30	(0.0)
Total				1,320	780	430	30	
Swap	NC4-OPIS-MB	0.8780		3,850	-	-	-	(6.1)
Swap	NC4-OPIS-MB	0.8114		-	2,260	-	-	(3.6)
Swap	NC4-OPIS-MB	0.7275		-	-	1,230	-	(2.4)
Swap	NC4-OPIS-MB	0.7560		-	-	-	86	(0.1)
Total				3,850	2,260	1,230	86	
Swap	C5-OPIS-MB	1.2034		2,540	-	-	-	(7.2)
Swap	C5-OPIS-MB	1.2291		-	1,919	-	-	(8.0)
Swap	C5-OPIS-MB	1.1337		-	-	760	-	(2.8)
Swap	C5-OPIS-MB	1.1600		-	-	-	54	(0.2)
Total				2,540	1,919	760	54	
		Put Price	Call Price					
Collar	C3-OPIS-MB	0.5300	0.6500	900	-	-	-	(2.1)
		Put Price	Call Price					
Collar	IC4-OPIS-MB	0.6500	0.8400	110	-	-	-	(0.2)
Collar	IC4-OPIS-MB	0.6400	0.8000	-	110	-	-	(0.3)
Total				110	110	-	-	

		Put Price	Call Price					
Collar	NC4-OPIS-MB	0.6500	0.8000	300	-	-	-	(0.7)
Collar	NC4-OPIS-MB	0.6400	0.7600	-	300	-	-	(0.9)
Total				300	300	-	-	
Gathering & Processing total				24,610	17,879	7,807	550	$ (77.5)
Other (1)(2)								
Future	C2-OPIS-MB	0.2596		3,098	-	-	-	$ (1.0)
Future	C2-OPIS-MB	0.2772		-	1,507	-	-	(0.1)
Future	C2-OPIS-MB	0.2820		-	-	3,115	-	(0.6)
Total				3,098	1,507	3,115	-	
Future	C3-OPIS-MB	0.8029		5,033	-	-	-	(5.4)
Future	C3-OPIS-MB	0.8786		-	438	-	-	(0.4)
Total				5,033	438	-	-	
Future	IC4-OPIS-MB	0.8525		489	-	-	-	(0.9)
Future	NC4-OPIS-MB	0.8665		1,793	-	-	-	(2.9)
Future	C5-OPIS-MB	1.8810		(136)	-	-	-	(0.3)
Other total				10,277	1,945	3,115	-	$ (11.6)
								$ (89.1)

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(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 2018	2019	2020	2021	Fair Value (In millions)
Gathering & Processing								
Swap	WTI-NYMEX	53.38		4,990	-	-	-	$ (15.7)
Swap	WTI-NYMEX	55.16		-	3,413	-	-	(12.5)
Swap	WTI-NYMEX	56.49		-	-	770	-	(1.2)
Swap	WTI-NYMEX	54.43		-	-	-	190	(0.3)
				4,990	3,413	770	190	
		Put Price	Call Price					
Collar	WTI-NYMEX	48.00	56.25	590	-	-	-	(1.6)
Collar	WTI-NYMEX	48.00	56.25	-	590	-	-	(2.3)
				590	590	-	-	
Total				5,580	4,003	770	190	
								$ (33.6)

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 16 - 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, 2018, 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, the TRP Revolver and the Securitization Facility will also increase. As of June 30, 2018, the Partnership had $180.0 million in outstanding variable rate borrowings under the TRP Revolver and Securitization Facility, and we had outstanding variable rate borrowings of $150.0 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 $1.8 million and our consolidated annual interest expense by $3.3 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 $75.9 million as of June 30, 2018. The range of losses attributable to our individual counterparties would be between $6.4 million and $22.3 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 performing initial and subsequent credit risk analyses, setting maximum credit limits and terms and requiring 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, 2018, our operating income would decrease by $8.7 million in the year of the assessment.

During the three and six months ended June 30, 2018, sales of commodities and fees from midstream services provided to Petredec (Europe) Limited comprised approximately 17% and 15% of our consolidated revenues. No customer comprised greater than 10% of our consolidated revenues in the three and six months ended June 30, 2017.

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, as of June 30, 2018, the design and operation of our disclosure controls and procedures were 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.

Changes in Internal Control Over Financial Reporting

During the three months ended June 30, 2018, we implemented a new enterprise resource planning ("ERP") system. The new ERP system consolidates two legacy ERP systems and represents a change in our internal control over financial reporting. We have taken steps to implement appropriate internal control over financial reporting during this period of change and will continue to evaluate the design and operating effectiveness of our internal controls during subsequent periods. We will complete our evaluation and testing of the internal control changes as of December 31, 2018.

Other than the ERP implementation, 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
April 1, 2018 - April 30, 2018	599	$ 48.03	—	—
May 1, 2018 - May 31, 2018	558	$ 46.97	—	—
June 1, 2018 - June 30, 2018	44,725	$ 49.59	—	—

(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	Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed December 12, 2017).
3.9	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)).
4.2	Indenture dated as of April 12, 2018 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed April 16, 2018).
4.3	

Registration Rights Agreement dated as of April 12, 2018 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed April 16, 2018).

10.1 Purchase Agreement dated as of April 5, 2018, among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed April 6, 2018).

10.2 First Amendment to Credit Agreement dated as of June 29, 2018, by and among Targa Resources Corp., Bank of America, N.A., and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed July 3, 2018 (File No. 001-34991)).

10.3 Third Amendment and Restatement Agreement dated as of June 29, 2018, by and among Targa Resources Partners LP, Bank of America, N.A., and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed July 3, 2018).

10.4* Supplemental Indenture dated July 24, 2018 to Indenture dated October 25, 2012, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association).

10.5* Supplemental Indenture dated July 24, 2018 to Indenture dated May 14, 2013, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association).

Number	Description
10.6*	Supplemental Indenture dated July 24, 2018 to Indenture dated October 28, 2014, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association).
10.7*	Supplemental Indenture dated July 24, 2018 to Indenture dated September 14, 2015, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association).
10.8*	Supplemental Indenture dated July 24, 2018 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association).
10.9*	Supplemental Indenture dated July 24, 2018 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association).
10.10*	Supplemental Indenture dated July 24, 2018 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association).
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

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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 8, 2018	By:	/s/ Jennifer R. Kneale Jennifer R. Kneale Chief Financial Officer (Principal Financial Officer)