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 March 31, 2019

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

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 every Interactive Data File required to be submitted 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 such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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	☐	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 ☑

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Trading Symbol(s)**	**Name of exchange on which registered**
Common Stock	TRGP	New York Stock Exchange

As of May 3, 2019, there were 232,475,006 shares of the registrant's common stock, $0.001 par value, outstanding.

TABLE OF CONTENTS

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 time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, by the use of forward-looking statements, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the 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 transportation and 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, the credit ratings for the Partnership's and our debt obligations, and demand for our common equity;
- 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, 2018 ("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 March 31, 2019 ("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.

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
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

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	March 31, 2019	December 31, 2018
	(Unaudited)	
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 124.9	$ 232.1
Trade receivables, net of allowances of $0.2 and $0.1 million at March 31, 2019 and December 31, 2018	752.8	865.5
Inventories	197.9	164.7
Assets from risk management activities	75.9	115.3
Other current assets	29.5	41.3
Total current assets	1,181.0	1,418.9
Property, plant and equipment	18,189.3	17,220.7
Accumulated depreciation and amortization	(4,485.9)	(4,292.3)
Property, plant and equipment, net	13,703.4	12,928.4
Intangible assets, net	1,940.2	1,983.2
Goodwill, net	46.6	46.6
Long-term assets from risk management activities	23.1	34.1
Investments in unconsolidated affiliates	605.9	490.5
Other long-term assets	69.0	36.5
Total assets	$ 17,569.2	$ 16,938.2
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,680.2	$ 1,737.3
Liabilities from risk management activities	43.3	33.6
Current debt obligations	318.1	1,027.9
Total current liabilities	2,041.6	2,798.8
Long-term debt	7,118.5	5,632.4
Long-term liabilities from risk management activities	9.4	3.1
Deferred income taxes, net	507.6	525.2
Other long-term liabilities	301.2	262.2
Contingencies (see Note 18)		
Series A Preferred 9.5% Stock, $1,000 per share liquidation preference, (1,200,000 shares authorized, 965,100 shares issued and outstanding), net of discount (see Note 12)	253.6	245.7
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300,000,000 shares authorized)	0.2	0.2
Issued / Outstanding		
March 31, 2019: 233,370,416 / 232,475,006		
December 31, 2018: 232,456,283 / 231,790,530		
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	5,925.7	6,154.9
Retained earnings (deficit)	(169.3)	(130.4)
Accumulated other comprehensive income (loss)	48.9	94.3
Treasury stock, at cost (895,410 shares as of March 31, 2019 and 665,753 shares as of December 31, 2018)	(49.2)	(39.6)
Total Targa Resources Corp. stockholders' equity	5,756.3	6,079.4
Noncontrolling interests	1,581.0	1,391.4
Total owners' equity	7,337.3	7,470.8
Total liabilities, Series A Preferred Stock and owners' equity	$ 17,569.2	$ 16,938.2

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended March 31,	
	2019	2018
	(Unaudited) (In millions, except per share amounts)	
Revenues:		
Sales of commodities	$ 1,976.5	$ 2,173.7
Fees from midstream services	322.9	281.9
Total revenues	2,299.4	2,455.6
Costs and expenses:		
Product purchases	1,726.0	1,941.0
Operating expenses	190.2	173.2
Depreciation and amortization expense	237.4	198.1
General and administrative expense	81.1	56.7
Other operating (income) expense	3.4	0.3
Income (loss) from operations	61.3	86.3
Other income (expense):		
Interest income (expense), net	(80.6)	16.1
Equity earnings (loss)	2.8	1.5
Gain (loss) from financing activities	(1.4)	—
Change in contingent considerations	(9.7)	(56.1)
Income (loss) before income taxes	(27.6)	47.8
Income tax (expense) benefit	2.9	(8.9)
Net income (loss)	(24.7)	38.9
Less: Net income (loss) attributable to noncontrolling interests	14.2	16.0
Net income (loss) attributable to Targa Resources Corp.	(38.9)	22.9
Dividends on Series A Preferred Stock	22.9	22.9
Deemed dividends on Series A Preferred Stock	7.9	7.0
Net income (loss) attributable to common shareholders	$ (69.7)	$ (7.0)
Net income (loss) per common share - basic	$ (0.30)	$ (0.03)
Net income (loss) per common share - diluted	$ (0.30)	$ (0.03)
Weighted average shares outstanding - basic	232.2	218.7
Weighted average shares outstanding - diluted	232.2	218.7

See notes to consolidated financial statements.

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

	Three Months Ended March 31,					
	2019			2018		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(Unaudited) (In millions)					
Net income (loss)			$ (24.7)			$ 38.9
Other comprehensive income (loss):						
Commodity hedging contracts:						
Change in fair value	$ (38.8)	$ 9.5	(29.3)	$ 64.6	$ (15.4)	49.2
Settlements reclassified to revenues	(21.3)	5.2	(16.1)	26.7	(6.4)	20.3
Other comprehensive income (loss)	(60.1)	14.7	(45.4)	91.3	(21.8)	69.5
Comprehensive income (loss)			(70.1)			108.4
Less: Comprehensive income (loss) attributable to noncontrolling interests			14.2			16.0
Comprehensive income (loss) attributable to Targa Resources Corp.			$ (84.3)			$ 92.4

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

	Common Stock		Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares		Noncontrolling Interests	Total Owner's Equity	Series A Preferred Stock
	Shares	Amount				Shares	Amount			
	(Unaudited) (In millions, except shares in thousands)									
Balance, December 31, 2018	**231,791**	**$ 0.2**	**$ 6,154.9**	**$ (130.4)**	**$ 94.3**	**666**	**$ (39.6)**	**$ 1,391.4**	**$ 7,470.8**	**$ 245.7**
Compensation on equity grants	—	—	16.5	—	—	—	—	—	16.5	—
Distribution equivalent rights	—	—	(3.6)	—	—	—	—	—	(3.6)	—
Shares issued under compensation program	913	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(229)	—	—	—	—	229	(9.6)	—	(9.6)	—
Series A Preferred Stock dividends										
Dividends - $23.75 per share	—	—	—	(22.9)	—	—	—	—	(22.9)	—
Dividends in excess of retained earnings	—	—	(22.9)	22.9	—	—	—	—	—	—
Deemed dividends - accretion of beneficial conversion feature	—	—	(7.9)	—	—	—	—	—	(7.9)	7.9
Common stock dividends										
Dividends - $0.91 per share	—	—	—	(211.3)	—	—	—	—	(211.3)	—
Dividends in excess of retained earnings	—	—	(211.3)	211.3	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(21.4)	(21.4)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	196.8	196.8	—
Other comprehensive income (loss)	—	—	—	—	(45.4)	—	—	—	(45.4)	—
Net income (loss)	—	—	—	(38.9)	—	—	—	14.2	(24.7)	—
Balance, March 31, 2019	**232,475**	**$ 0.2**	**$ 5,925.7**	**$ (169.3)**	**$ 48.9**	**895**	**$ (49.2)**	**$ 1,581.0**	**$ 7,337.3**	**$ 253.6**

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY AND SERIES A PREFERRED STOCK

	Common Stock		Additional Paid in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Treasury Shares		Noncontrolling Interests	Total Owner's Equity	Series A Preferred Stock
	Shares	Amount				Shares	Amount			
	(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	—	—	—	5.2	(5.2)	—	—	—	—	—
Compensation on equity grants	—	—	13.2	—	—	—	—	—	13.2	—
Distribution equivalent rights	—	—	(3.3)	—	—	—	—	—	(3.3)	—
Shares issued under compensation program	51	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(8)	—	—	—	—	8	(0.4)	—	(0.4)	—
Issuance of common stock	1,163	—	57.7	—	—	—	—	—	57.7	—
Exercise of warrants - shares settled	59	—	—	—	—	—	—	—	—	—
Series A Preferred Stock dividends										
Dividends - $23.75 per share	—	—	—	(22.9)	—	—	—	—	(22.9)	—
Dividends in excess of retained earnings	—	—	(22.9)	22.9	—	—	—	—	—	—
Deemed dividends - accretion of beneficial conversion feature	—	—	(7.0)	—	—	—	—	—	(7.0)	7.0
Common stock dividends										
Dividends - $0.91 per share	—	—	—	(199.3)	—	—	—	—	(199.3)	—
Dividends in excess of retained earnings	—	—	(199.3)	199.3	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(19.3)	(19.3)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	280.1	280.1	—
Acquisition of related party	—	—	—	—	—	—	—	1.2	1.2	—
Other comprehensive income (loss)	—	—	—	—	69.5	—	—	—	69.5	—
Net income (loss)	—	—	—	22.9	—	—	—	16.0	38.9	—
Balance, March 31, 2018	**218,832**	**$ 0.2**	**$ 6,141.2**	**$ (49.1)**	**$ 34.4**	**594**	**$ (36.0)**	**$ 873.7**	**$ 6,964.4**	**$ 223.5**

See notes to consolidated financial statements.

TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
	(Unaudited) (In millions)	
Cash flows from operating activities		
Net income (loss)	$ (24.7)	$ 38.9
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Amortization in interest expense	2.6	2.7
Compensation on equity grants	16.5	13.2
Depreciation and amortization expense	237.4	198.1
Accretion of asset retirement obligations	1.0	0.9
Increase (decrease) in redemption value of mandatorily redeemable preferred interests	—	(72.5)
Deferred income tax expense (benefit)	(2.9)	8.9
Equity (earnings) loss of unconsolidated affiliates	(2.8)	(1.5)
Distributions of earnings received from unconsolidated affiliates	4.8	4.2
Risk management activities	7.2	10.9
(Gain) loss on sale or disposition of assets	3.2	(0.1)
(Gain) loss from financing activities	1.4	—
Change in contingent considerations	9.7	56.1
Changes in operating assets and liabilities, net of business acquisitions:		
Receivables and other assets	78.2	123.7
Inventories	(60.6)	110.2
Accounts payable and other liabilities	36.6	(139.3)
Net cash provided by operating activities	307.6	354.4
Cash flows from investing activities		
Outlays for property, plant and equipment	(943.3)	(595.9)
Proceeds from sale of assets	0.5	—
Investments in unconsolidated affiliates	(117.4)	(88.0)
Return of capital from unconsolidated affiliates	—	1.5
Other, net	(9.0)	5.1
Net cash used in investing activities	(1,069.2)	(677.3)
Cash flows from financing activities		
Debt obligations:		
Proceeds from borrowings under credit facilities	765.0	640.0
Repayments of credit facilities	(795.0)	(280.0)
Proceeds from borrowings under accounts receivable securitization facility	378.0	—
Repayments of accounts receivable securitization facility	(350.4)	(50.0)
Proceeds from issuance of senior notes	1,500.0	—
Redemption of senior notes	(749.4)	—
Principal payments of finance leases	(2.7)	—
Proceeds from issuance of common stock	—	58.1
Costs incurred in connection with financing arrangements	(12.8)	(0.4)
Repurchase of shares and units under compensation plans	(9.6)	(0.4)
Contributions from noncontrolling interests	196.8	280.1
Distributions to noncontrolling interests	(18.6)	(16.5)
Distributions to Partnership unitholders	(2.8)	(2.8)
Dividends paid to common and Series A preferred shareholders	(244.1)	(222.6)
Net cash provided by financing activities	654.4	405.5
Net change in cash and cash equivalents	(107.2)	82.6
Cash and cash equivalents, beginning of period	232.1	137.2
Cash and cash equivalents, end of period	$ 124.9	$ 219.8

See notes to consolidated financial statements.

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 primarily engaged in the business of:

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

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

Note 2 — Basis of Presentation

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and do not include all information and disclosures required by GAAP. Therefore, this information should be read in conjunction with our consolidated financial statements and notes contained in our Annual Report. The information furnished herein reflects all adjustments that are, in the opinion of management, necessary for a fair statement of the results of the interim periods reported. 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. Operating results for the three months ended March 31, 2019, are not necessarily indicative of the results that may be expected for the year ending December 31, 2019.

Note 3 — Significant Accounting Policies

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. Other than the updates noted below, there were no significant updates or revisions to our accounting policies during the three months ended March 31, 2019.

Recent Accounting Pronouncements

Recently adopted accounting pronouncements

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 supersede the leases guidance in Topic 840. We adopted Topic 842 on January 1, 2019 by applying the optional transition method in ASU-2018-11, 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. The adoption of Topic 842 did not result in a cumulative effect adjustment to retained earnings on January 1, 2019. As part of the adoption of Topic 842, we recognized a net right-of-use asset of $74.6 million (net of $16.3 million of lease incentives/deferred rent) and lease liability of $90.9 million. Other practical expedients we elected include:

- The package for transition relief, which among other things, allows us to carry forward the historical lease classification;
- The land easements transition, which allows us to carry forward our historical accounting treatment for land easements prior to the effective date of the new leases standard and evaluate under Topic 842 only new or modified land easements on or after January 1, 2019;

- The short-term lease election, which allows us to elect by all asset classes not to record on the balance sheet a lease whose initial term is twelve months or less;
- The election to not separate non-lease components from lease components for all the asset classes in our current lease portfolio, where Targa is the lessee; and
- The election to not separate non-lease components from lease components for gathering, processing and storage assets, where Targa is the lessor. Based on our election, we determined the non-lease component in certain of these arrangements is the predominant component, and therefore, account for the arrangements under ASC 606.

We recognize the following for all leases (with the exception of short-term leases) at the commencement date:

- A lease liability, which is a lessee's obligation to make lease payments arising from a lease.
- 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.

We determine if an arrangement is or contains a lease at inception. Leases with an initial term of twelve months or less are considered short-term leases, which are excluded from the balance sheet. Right-of-use assets and lease liabilities are recognized at the commencement date based on the present value of future lease payments over the lease term. The right-of-use asset also includes any lease prepayments and excludes lease incentives. As most of the Company's leases do not provide an implicit interest rate, we use our incremental borrowing rate as the discount rate to compute the present value of our lease liability. The discount rate applied is determined based on information available on the date of adoption for all leases existing as of that date, and on the date of lease commencement for all subsequent leases.

Our lease arrangements may include variable lease payments based on an index or market rate or may be based on performance. For variable lease payments based on an index or market rate, we estimate and apply a rate based on information available at the commencement date. Variable lease payments based on performance are excluded from the calculation of the right-of-use asset and lease liability, and are recognized in our Consolidated Statements of Operations when the contingency underlying such variable lease payments is resolved. Our lease terms may include options to extend or terminate the lease. Such options are included in the measurement of our right-of-use asset and liability, provided we determine that we are reasonably certain to exercise the option.

See Note 11 – Leases for additional details.

Recently issued accounting pronouncements not yet adopted

Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract

In August 2018, the FASB issued ASU 2018-15, *Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract*. The amendments in this update require customers in a cloud computing arrangement that is a service contract to assess related implementation costs for capitalization using the same approach as implementation costs associated with internal-use software. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2019, with early adoption permitted. Entities may apply the amendments using a retrospective or prospective transition method. The amendments will be effective for Targa in the first quarter of 2020. We currently plan to apply the prospective transition method and do not expect a material impact on our Consolidated Financial Statements.

Note 4 — Divestitures

Subsequent Event

Train 7 Joint Venture

In February 2019, we announced an extension of Grand Prix from Southern Oklahoma to the STACK region of Central Oklahoma where it will connect with the Williams Companies, Inc. ("Williams") Bluestem Pipeline and link the Conway, Kansas, and Mont Belvieu, Texas, NGL markets. In connection with this project, Williams has committed significant volumes to us that we will transport on Grand Prix and fractionate at our Mont Belvieu facilities. Williams also had an initial option to purchase a 20% equity interest in one of our recently announced 110 MBbl/d fractionation trains (Train 7 or Train 8) in Mont Belvieu. Williams exercised its option to acquire a 20% equity interest in Train 7 and subsequently executed a joint venture agreement with us in the second quarter of 2019. Certain fractionation-related infrastructure for Train 7, including storage caverns and brine handling, will be funded and owned 100% by Targa.

Sale of Interest in Targa Badlands LLC

On April 3, 2019, we closed on the sale of a 45% interest in Targa Badlands LLC, the entity that holds substantially all of our assets in North Dakota, to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities (collectively, “Blackstone”) for $1.6 billion in cash. We used the net cash proceeds to repay debt and for general corporate purposes, including funding our growth capital program. We continue to be the operator of Targa Badlands LLC and hold majority governance rights. Future growth capital of Targa Badlands LLC is expected to be funded on a pro rata ownership basis. Targa Badlands LLC will pay a minimum quarterly distribution (“MQD”) to Blackstone and Targa, with Blackstone having a priority right on such MQDs. Additionally, Blackstone’s capital contributions would have a liquidation preference upon a sale of Targa Badlands LLC. We will continue to present Targa Badlands LLC on a consolidated basis in our consolidated financial statements.

Note 5 — Inventories

	March 31, 2019	December 31, 2018
Commodities	$ 176.4	$ 151.1
Materials and supplies	21.5	13.6
	$ 197.9	$ 164.7

Note 6 — Property, Plant and Equipment and Intangible Assets

	March 31, 2019	December 31, 2018	Estimated Useful Lives (In Years)
Gathering systems	$ 8,427.6	$ 7,547.9	5 to 20
Processing and fractionation facilities	4,294.1	4,007.7	5 to 25
Terminaling and storage facilities	1,173.0	1,138.7	5 to 25
Transportation assets	1,016.8	445.1	10 to 25
Other property, plant and equipment	398.9	334.5	3 to 25
Land	149.3	144.3	—
Construction in progress	2,688.7	3,602.5	—
Finance lease right-of-use assets	40.9	—	
Property, plant and equipment	18,189.3	17,220.7	
Accumulated depreciation and amortization	(4,485.9)	(4,292.3)	
Property, plant and equipment, net	$ 13,703.4	$ 12,928.4	
Intangible assets	$ 2,736.6	$ 2,736.6	10 to 20
Accumulated amortization	(796.4)	(753.4)	
Intangible assets, net	$ 1,940.2	$ 1,983.2	

During the preparation of the Company's consolidated financial statements for the three months ended March 31, 2019, the Company identified an error related to depreciation expense on certain assets that should have been placed in-service during 2018. The Company does not believe this error is material to its previously issued historical consolidated financial statements for any of the periods impacted and accordingly, has not adjusted the historical financial statements. The Company has recorded the cumulative impact of the adjustment in the three months ended March 31, 2019. This adjustment resulted in a one-time $12.5 million overstatement of depreciation expense during the three months ended March 31, 2019.

During the three months ended March 31, 2019 and 2018, depreciation expense was $194.4 million and $152.4 million.

Intangible Assets

Intangible assets consist of customer contracts and customer relationships acquired in prior business combinations. The fair value of these acquired intangible assets were determined at the date of acquisition based on the present values of estimated future cash flows. 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 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 $171.6 million, $159.4 million, $149.5 million, $141.2 million and $136.0 million for each of the years 2019 through 2023.

The changes in our intangible assets are as follows:

Balance at December 31, 2018	$	1,983.2
Amortization		(43.0)
Balance at March 31, 2019	$	1,940.2

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”);
- two non-operated joint ventures in South Texas: a 75% interest in T2 LaSalle Gathering Company L.L.C. (“T2 LaSalle”), a gas gathering company, and a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (“T2 Eagle Ford”), a gas gathering company, (together the “T2 Joint Ventures”);
- a 50% operated ownership interest in Cayenne Pipeline, LLC, a joint venture with American Midstream LLC that owns a 62-mile gas pipeline to an NGL pipeline, which connects the VESCO plant in Venice, Louisiana to the Enterprise Products Operating LLC (“Enterprise”) pipeline at Toca, Louisiana, for delivery to Enterprise’s Norco Fractionator (the “Cayenne Joint Venture”);
- a 25% non-operated ownership interest in Gulf Coast Express Pipeline LLC (“GCX”);
- a 50% operated ownership interest in Little Missouri 4 LLC (the “Little Missouri 4 Joint Venture”), a joint venture to construct a new 200 MMcf/d natural gas processing plant at Targa’s existing Little Missouri facility; and
- a 10% non-operated ownership interest in Delaware Basin Residue, LLC (the “Agua Blanca Joint Venture”), a joint venture with affiliates of First Infrastructure Capital Advisors LLC and Markwest Energy Partners, L.P. in the Agua Blanca pipeline.

Investments in GCF, the Cayenne Joint Venture, GCX and the Agua Blanca Joint Venture are included in the total assets of our Logistics and Marketing segment. Investments in the T2 Joint Ventures and the Little Missouri 4 Joint Venture are included in the total assets of our Gathering and Processing segment. See Note 21 – Segment Information for more information regarding our segment assets.

The terms of these joint venture agreements do not afford us the degree of control required for consolidating them in our consolidated financial statements, but do afford us the significant influence required to employ the equity method of accounting.

The T2 Joint Ventures were formed to provide services for the benefit of their joint interest owners and have capacity lease agreements with their joint interest owners, which cover costs of operations (excluding depreciation and amortization). On April 1, 2019, we assumed the operatorship of the T2 Joint Ventures.

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

	Balance at December 31, 2018	Equity Earnings (Loss)	Cash Distributions	Contributions	Balance at March 31, 2019
GCF	$ 40.3	$ 4.3	$ (2.2)	$ —	$ 42.4
T2 LaSalle (1)	49.3	(1.5)	—	—	47.8
T2 Eagle Ford (1)	99.0	(2.4)	—	—	96.6
Cayenne	16.6	1.9	(2.6)	—	15.9
GCX (2)	211.6	0.6	—	110.4	322.6
Little Missouri 4	67.3	—	—	7.0	74.3
Agua Blanca	6.4	(0.1)	—	—	6.3
Total	$ 490.5	$ 2.8	$ (4.8)	$ 117.4	$ 605.9

(1) As of March 31, 2019, $24.3 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.

(2) Our 25% interest in GCX is owned by Targa GCX Pipeline LLC (“GCX DevCo JV”), of which we own a 20% interest. GCX DevCo JV is accounted for on a consolidated basis in our consolidated financial statements.

Note 8 — Accounts Payable and Accrued Liabilities

	March 31, 2019	December 31, 2018
Commodities	$ 779.3	$ 721.9
Other goods and services	388.0	478.6
Interest	91.6	79.9
Income and other taxes	40.5	47.7
Permian Acquisition contingent consideration	317.9	308.2
Compensation and benefits	26.5	57.3
Preferred Series A dividends payable	22.9	22.9
Other	13.5	20.8
	$ 1,680.2	$ 1,737.3

Accounts payable and accrued liabilities includes $29.3 million and $52.6 million of liabilities to creditors to whom we have issued checks that remained outstanding as of March 31, 2019 and December 31, 2018.

Permian Acquisition Contingent Consideration

As a result of a 2017 acquisition of certain gas gathering and processing and crude gathering assets in the Permian Basin (the "Permian Acquisition"), we have included the related contingent consideration in accounts payable and accrued liabilities as of March 31, 2019, and December 31, 2018. The Permian Acquisition contingent consideration represents the second earn-out payment, which will be paid in May 2019, and is derived on a multiple of realized gross margin during the earn-out period from contracts that existed on March 1, 2017, in accordance with the terms of the purchase and sale agreements. The first potential earn-out payment would have occurred in May 2018 and expired with no required payment.

Changes in the value of the contingent consideration liability have been included in Other income (expense). For the period from December 31, 2018 to March 31, 2019, the value of the contingent consideration increased by $9.7 million, primarily attributable to the elimination of discounting and an increase in actual gross margin through the end of the earn-out period. During the three months ended March 31, 2018, we recognized $56.0 million of expense in Other income (expense) related to the change in fair value of the contingent consideration.

See Note 17 – Fair Value Measurements for additional discussion of the fair value methodology.

Note 9 — Debt Obligations

	March 31, 2019	December 31, 2018
Current:		
Obligations of the Partnership: (1)		
Accounts receivable securitization facility, due December 2019 (2)	$ 307.6	$ 280.0
Senior unsecured notes, 4⅛% fixed rate, due November 2019	—	749.4
	307.6	1,029.4
Debt issuance costs, net of amortization	—	(1.5)
Finance lease liabilities	10.5	—
Current debt obligations	318.1	1,027.9
Long-term:		
TRC obligations:		
TRC Senior secured revolving credit facility, variable rate, due June 2023 (3)	435.0	435.0
Obligations of the Partnership: (1)		
Senior secured revolving credit facility, variable rate, due June 2023 (4)	670.0	700.0
Senior unsecured notes:		
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
5⅛% fixed rate, due February 2025	500.0	500.0
5⅞% fixed rate, due April 2026	1,000.0	1,000.0
5⅜% fixed rate, due February 2027	500.0	500.0
6½% fixed rate, due July 2027	750.0	—
5% fixed rate, due January 2028	750.0	750.0
6⅞% fixed rate, due January 2029	750.0	—
TPL notes, 4¾% fixed rate, due November 2021 (5)	6.5	6.5
TPL notes, 5⅞% fixed rate, due August 2023 (5)	48.1	48.1
Unamortized premium	0.3	0.3
	7,133.5	5,663.5
Debt issuance costs, net of amortization	(42.7)	(31.1)
Finance lease liabilities	27.7	—
Long-term debt	7,118.5	5,632.4
Total debt obligations	$ 7,436.6	$ 6,660.3
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)	69.8	79.5
	$ 69.8	$ 79.5

(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 March 31, 2019, the Partnership had $337.6 million of qualifying receivables under its $400.0 million accounts receivable securitization facility, resulting in availability of $30.0 million.
(3) As of March 31, 2019, availability under TRC's $670.0 million senior secured revolving credit facility ("TRC Revolver") was $235.0 million.
(4) As of March 31, 2019, availability under the Partnership's $2.2 billion senior secured revolving credit facility ("TRP Revolver") was $1,460.2 million.
(5) "TPL" refers to Targa Pipeline Partners LP.

The following table shows the range of interest rates and weighted average interest rate incurred on variable-rate debt obligations during the three months ended March 31, 2019:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC Revolver	4.2% - 4.3%	4.3%
TRP Revolver	3.8% - 4.3%	4.1%
Partnership's accounts receivable securitization facility	3.4%	3.4%

Compliance with Debt Covenants

As of March 31, 2019, we were in compliance with the covenants contained in our various debt agreements.

Senior Unsecured Notes Issuances

In January 2019, the Partnership issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6⅞% Senior Notes due January 2029, resulting in total net proceeds of $1,487.3 million. The net proceeds from the offerings were used to redeem in full the Partnership's outstanding 4⅛% Senior Notes due 2019 with the remainder used for general partnership purposes, which included repaying borrowings under the Partnership's credit facilities.

Debt Extinguishment

In February 2019, the Partnership redeemed in full its outstanding 4⅛% Senior Notes due 2019 at par value plus accrued interest through the redemption date. The redemption resulted in a non-cash loss to write-off $1.4 million of unamortized debt issuance costs, which is included in Gain (loss) from financing activities in the Consolidated Statements of Operations.

Note 10 — Other Long-term Liabilities

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

	March 31, 2019	December 31, 2018
Asset retirement obligations	$ 63.9	$ 55.5
Deferred revenue	174.6	175.5
Operating lease liabilities	47.8	—
Other liabilities	14.9	31.2
Total long-term liabilities	$ 301.2	$ 262.2

Asset Retirement Obligations

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

Deferred Revenue

We have certain long-term contractual arrangements for which we have received consideration that we are not yet able to recognize as revenue. The resulting deferred revenue will be recognized once all conditions for revenue recognition have been met.

Deferred revenue includes $129.0 million of payments received from Vitol Americas Corp. ("Vitol") (formerly known as Noble Americas Corp.), a subsidiary of Vitol US Holding Co., in 2016, 2017, and 2018 as part of an agreement (the "Splitter Agreement") related to the construction and operation of a crude oil and condensate splitter. In December 2018, Vitol elected to terminate the Splitter Agreement. The Splitter Agreement provides that the first three annual payments are ours if Vitol elects to terminate, which Vitol disputes. The timing of revenue recognition related to the Splitter Agreement deferred revenue is currently dependent upon resolution of the dispute with Vitol. 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, 2018	$ 175.5
Additions	—
Revenue recognized	(0.9)
Balance at March 31, 2019	$ 174.6

Note 11 – Leases

We have non-cancellable operating leases primarily associated with our office facilities, rail assets, land, and storage and terminal assets. We have finance leases primarily associated with our tractors and vehicles. Our leases have remaining lease terms of 1 to 11 years, some of which include options to extend the lease term for up to 20 years.

The balances of right-of-use assets and liabilities of finance leases and operating leases, and their locations on our Consolidated Balance Sheets are as follows:

	Balance Sheet Location	March 31, 2019
Right-of-use assets		
Operating leases, gross	Other long-term assets	$ 35.6
Finance leases, gross	Property, plant and equipment	40.9
Lease liabilities		
Current:		
Operating leases	Accounts payable and accrued liabilities	$ 2.7
Finance leases	Current debt obligations	10.5
Non-current:		
Operating leases	Other long-term liabilities	47.8
Finance leases	Long-term debt	27.7

Operating lease costs and short-term lease costs are included in Operating expenses or General and administrative expense in our Consolidated Statements of Operations, depending on the nature of the leases. Finance lease costs are included in Depreciation and amortization expense and Interest income (expense) in our Consolidated Statements of Operations. The components of lease expense were as follows:

	Three Months Ended March 31, 2019
Lease cost	
Operating lease cost	$ 2.3
Short-term lease cost	7.6
Variable lease cost	1.2
Finance lease cost	
Amortization of right-of-use assets	3.1
Interest expense	0.4
Total lease cost	$ 14.6

Other supplemental information related to our leases are as follows:

	Three Months Ended March 31, 2019
Cash paid for amounts included in the measurement of lease liabilities	
Operating cash flows for operating leases	$ 2.0
Operating cash flows for finance leases	0.4
Financing cash flows for finance leases	2.7

The weighted-average remaining lease terms for operating leases and finance leases are 8 years and 3 years, respectively. The weighted-average discount rates for operating leases and finance leases are 4.0% and 3.9%, respectively.

The following table presents the maturities of our lease liabilities under non-cancellable leases as of March 31, 2019:

	Operating Leases	Finance Leases
Future Minimum Lease Payments Beginning After March 31,		
2019	$ 4.7	$ 11.8
2020	8.9	11.0
2021	9.0	9.2
2022	8.0	8.2
2023	6.2	1.0
Thereafter	23.5	—
Total undiscounted cash flows	60.3	41.2
Less imputed interest	(9.8)	(3.0)
Total lease liabilities	$ 50.5	$ 38.2

The following table presents future minimum payments under non-cancellable leases as of December 31, 2018:

	Leases
2019	$ 20.9
2020	20.2
2021	18.5
2022	16.5
2023	9.8
Thereafter	24.9
Total payments	$ 110.8

Note 12 – Preferred Stock

Preferred Stock Dividends

As of March 31, 2019, we have accrued cumulative preferred dividends of $22.9 million on our Series A Preferred Stock (“Series A Preferred”), which will be paid on May 14, 2019. During the three months ended March 31, 2019, we paid $22.9 million of dividends to preferred shareholders, and recorded deemed dividends of $7.9 million attributable to accretion of the preferred discount resulting from the beneficial conversion feature accounting. Such accretion is included in the book value of the Series A Preferred.

Note 13 — Common Stock and Related Matters

Common Stock Dividends

The following table details the dividends declared and/or paid by us to common shareholders for the three months ended March 31, 2019:

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)			
March 31, 2019	May 15, 2019	$ 215.2	$ 211.5	$ 3.7	$ 0.91000
December 31, 2018	February 15, 2019	215.2	211.2	4.0	0.91000

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

Note 14 — 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 and paid by the Partnership for the three months ended March 31, 2019:

Three Months Ended	Date Paid	Total Distributions	Distributions to Targa Resources Corp.
March 31, 2019	April 5, 2019	$ 437.8	$ 435.0
December 31, 2018	February 13, 2019	241.3	238.5

Contributions

All capital contributions to the Partnership 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 three months ended March 31, 2019, we did not make contributions to the Partnership.

Preferred Units

The Partnership's issued and outstanding Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "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 of distributions to the holders of Preferred Units ("Preferred Unitholders") for the three months ended March 31, 2019. The Preferred Units are reported as noncontrolling interests in our financial statements.

Subsequent Event

In April 2019, 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 May 15, 2019.

Note 15 — Earnings per Common Share

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
Net income (loss)	$ (24.7)	$ 38.9
Less: Net income attributable to noncontrolling interests	14.2	16.0
Less: Dividends on preferred stock	30.8	29.9
Net income attributable to common shareholders for basic earnings per share	$ (69.7)	$ (7.0)
Weighted average shares outstanding - basic	232.2	218.7
Net income available per common share - basic	$ (0.30)	$ (0.03)
Weighted average shares outstanding	232.2	218.7
Weighted average shares outstanding - diluted	232.2	218.7
Net income available per common share - diluted	$ (0.30)	$ (0.03)

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 March 31,	
	2019	2018
Unvested restricted stock awards	1.3	1.6
Series A Preferred Stock (1)	46.5	46.5

(1) The Series A Preferred has no mandatory redemption date, but is redeemable at our election in year six for a 10% premium to the liquidation preference and for a 5% premium to the liquidation preference in year seven and thereafter. If the Series A Preferred is not redeemed by the end of year twelve, the investors have the right to convert the Series A Preferred into TRC common stock. See Note 12 – Preferred Stock.

Note 16 — Derivative Instruments and Hedging Activities

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have entered into derivative instruments to hedge the commodity price risks 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, (ii) future commodity purchases and sales in our Logistics and Marketing segment and (iii) natural gas transportation basis risk in our Logistics and Marketing segment. The hedge positions associated with (i) and (ii) above will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices and are designated 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 March 31, 2019, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2019	2020	2021	2022	2023
Natural Gas	Swaps	MMBtu/d	175,364	79,930	52,055	-	-
Natural Gas	Basis Swaps	MMBtu/d	111,100	189,119	166,658	150,000	95,000
NGL	Swaps	Bbl/d	17,903	13,267	3,676	-	-
NGL	Futures	Bbl/d	9,735	4,645	-	-	-
NGL	Options	Bbl/d	410	-	-	-	-
Condensate	Swaps	Bbl/d	4,266	2,390	1,404	-	-
Condensate	Options	Bbl/d	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 value 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 March 31, 2019		Fair Value as of December 31, 2018	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 72.5	$ 25.2	$ 112.5	$ 18.9
	Long-term	20.4	3.1	31.6	1.5
Total derivatives designated as hedging instruments		$ 92.9	$ 28.3	$ 144.1	$ 20.4
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 3.4	$ 18.1	$ 2.8	$ 14.7
	Long-term	2.7	6.3	2.5	1.6
Total derivatives not designated as hedging instruments		$ 6.1	$ 24.4	$ 5.3	$ 16.3
Total current position		$ 75.9	$ 43.3	$ 115.3	$ 33.6
Total long-term position		23.1	9.4	34.1	3.1
Total derivatives		$ 99.0	$ 52.7	$ 149.4	$ 36.7

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	
March 31, 2019	**Asset**	**Liability**	**Collateral**	**Asset**	**Liability**
Current Position					
Counterparties with offsetting positions or collateral	$ 69.0	$ (42.0)	$ (7.3)	$ 43.5	$ (23.8)
Counterparties without offsetting positions - assets	6.9	-	-	6.9	-
Counterparties without offsetting positions - liabilities	-	(1.3)	-	-	(1.3)
	75.9	(43.3)	(7.3)	50.4	(25.1)
Long Term Position					
Counterparties with offsetting positions or collateral	19.0	(9.1)	-	13.5	(3.6)
Counterparties without offsetting positions - assets	4.1	-	-	4.1	-
Counterparties without offsetting positions - liabilities	-	(0.3)	-	-	(0.3)
	23.1	(9.4)	-	17.6	(3.9)
Total Derivatives					
Counterparties with offsetting positions or collateral	88.0	(51.1)	(7.3)	57.0	(27.4)
Counterparties without offsetting positions - assets	11.0	-	-	11.0	-
Counterparties without offsetting positions - liabilities	-	(1.6)	-	-	(1.6)
	$ 99.0	$ (52.7)	$ (7.3)	$ 68.0	$ (29.0)

	Gross Presentation			Pro Forma Net Presentation	
December 31, 2018	**Asset**	**Liability**	**Collateral**	**Asset**	**Liability**
Current Position					
Counterparties with offsetting positions or collateral	$ 100.0	$ (33.6)	$ (14.2)	$ 70.0	$ (17.8)
Counterparties without offsetting positions - assets	15.3	-	-	15.3	-
Counterparties without offsetting positions - liabilities	-	-	-	-	-
	115.3	(33.6)	(14.2)	85.3	(17.8)
Long Term Position					
Counterparties with offsetting positions or collateral	8.9	(3.1)	-	5.9	(0.1)
Counterparties without offsetting positions - assets	25.2	-	-	25.2	-
Counterparties without offsetting positions - liabilities	-	-	-	-	-
	34.1	(3.1)	-	31.1	(0.1)
Total Derivatives					
Counterparties with offsetting positions or collateral	108.9	(36.7)	(14.2)	75.9	(17.9)
Counterparties without offsetting positions - assets	40.5	-	-	40.5	-
Counterparties without offsetting positions - liabilities	-	-	-	-	-
	$ 149.4	$ (36.7)	$ (14.2)	$ 116.4	$ (17.9)

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 value of our derivative instruments.

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net asset of $46.3 million as of March 31, 2019. 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 ("OCI") and amounts reclassified from OCI to revenue for the periods indicated:

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)	
	Three Months Ended March 31,	
Derivatives in Cash Flow Hedging Relationships	2019	2018
Commodity contracts	$ (38.8)	$ 64.6

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)	
	Three Months Ended March 31,	
Location of Gain (Loss)	2019	2018
Revenues	$ 21.3	$ (26.7)

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.

		Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	2019	2018
Commodity contracts	Revenue	$ (9.5)	$ (10.8)

Based on valuations as of March 31, 2019, we expect to reclassify commodity hedge-related deferred gains of $64.6 million included in accumulated other comprehensive income into earnings before income taxes through the end of 2021, with $47.3 million of gains to be reclassified over the next twelve months.

See Note 17 – Fair Value Measurements and Note 21 – Segment Information for additional disclosures related to derivative instruments and hedging activities.

Note 17 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments and contingent consideration related to business acquisitions are reported at fair value 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 March 31, 2019, a net asset position of $46.3 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 $40.1 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $129.2 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 until the end of the related earn-out period.

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:

	March 31, 2019				
	Carrying Value	Fair 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)	$ 97.2	$ 97.2	$ —	$ 93.3	$ 3.9
Liabilities from commodity derivative contracts (1)	50.9	50.9	—	50.5	0.4
TPL contingent consideration (2)	2.4	2.4	—	—	2.4
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	124.9	124.9	—	—	—
TRC Revolver	435.0	435.0	—	435.0	—
TRP Revolver	670.0	670.0	—	670.0	—
Partnership's Senior unsecured notes	6,028.5	6,268.9	—	6,268.9	—
Partnership's accounts receivable securitization facility	307.6	307.6	—	307.6	—

	December 31, 2018				
	Carrying Value	Fair 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)	$ 144.4	$ 144.4	$ —	$ 137.5	$ 6.9
Liabilities from commodity derivative contracts (1)	31.7	31.7	—	31.3	0.4
Permian Acquisition contingent consideration (3)	308.2	308.2	—	—	308.2
TPL contingent consideration (2)	2.4	2.4	—	—	2.4
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	232.1	232.1	—	—	—
TRC Revolver	435.0	435.0	—	435.0	—
TRP Revolver	700.0	700.0	—	700.0	—
Partnership's Senior unsecured notes	5,277.9	5,088.9	—	5,088.9	—
Partnership's accounts receivable securitization facility	280.0	280.0	—	280.0	—

(1) The fair value of derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 16 – Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.

(2) We have a contingent consideration liability for TPL's previous acquisition of a gas gathering system and related assets, which is carried at fair value.

(3) We have a contingent consideration liability related to the Permian Acquisition, which was carried at fair value as of December 31, 2018. See Note 8 – Accounts Payable and Accrued Liabilities.

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 market prices or implied volatilities 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 March 31, 2019, we had 13 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 as of December 31, 2018, 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. The Permian Acquisition contingent consideration earn-out period ended on February 28, 2019. The first earn-out payment due in May 2018 expired with no required payment. The second earn-out payment will be paid in May 2019 and is derived on a multiple of realized gross margin during the earn-out period from contracts that existed on March 1, 2017, in accordance with the terms of the purchase and sale agreements. As such, the carrying value of the Permian Acquisition contingent consideration as of March 31, 2019, approximates fair value, as with our other accounts payables. See Note 8 – Accounts Payable and Accrued Liabilities for additional discussion of the Permian Acquisition contingent consideration.

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 Consideration
Balance, December 31, 2018	$ 6.5	$ (310.6)
Completion of Permian Acquisition contingent consideration earn-out period	-	308.2
Unrealized gain/(loss) included in OCI	(3.1)	-
Balance, March 31, 2019	$ 3.4	$ (2.4)

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. We and the Partnership are also parties to various proceedings with governmental environmental agencies in 2019, including but not limited to the Environmental Protection Agency, Texas Commission on Environmental Quality, Oklahoma Department of Environmental Quality, New Mexico Environment Department, Louisiana Department of Environmental Quality and North Dakota Department of Environmental Quality, which assert penalties for alleged violations of environmental regulations, including air emissions, discharges into the environment and reporting deficiencies, related to events that have arisen at certain of our facilities in the ordinary course of our business.

On February 26, 2019, the U.S. Environmental Protection Agency Region 8 and Targa Badlands LLC entered into a Final Order and Consent Agreement in connection with Targa Badlands LLC's alleged violation of Subpart ZZZZ of the National Emission Standards for Hazardous Air Pollutants at its Junction Compressor Station in McKenzie County, North Dakota. The Consent Agreement imposed a $220,000 civil penalty and requires certain compliance improvements.

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 gathering and processing, fractionation, export, terminaling and storage agreements.

	2019	2020	2021 and after
Fixed consideration to be recognized as of March 31, 2019	$ 394.3	$ 463.0	$ 3,327.5

In accordance with the optional exemptions that we elected to apply, the amounts presented in the table above 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 that 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; the estimated remaining duration of such contracts primarily ranges from 1 to 20 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 disclosures related to disaggregated revenue, see Note 21 – Segment Information.

Note 20 - Supplemental Cash Flow Information

	Three Months Ended March 31,	
	2019	2018
Cash:		
Interest paid, net of capitalized interest (1)	$ 66.1	$ 42.8
Income taxes paid, net of refunds	0.3	—
Non-cash investing activities:		
Deadstock commodity inventory transferred to property, plant and equipment	$ 17.5	1.7
Impact of capital expenditure accruals on property, plant and equipment	(38.8)	(22.3)
Transfers from materials and supplies inventory to property, plant and equipment	1.1	0.4
Contribution of property, plant and equipment to investments in unconsolidated affiliates	—	16.0
Change in ARO liability and property, plant and equipment	7.4	2.1
Non-cash financing activities:		
Reduction of Owner's Equity related to accrued dividends on unvested equity awards under share compensation arrangements	$ 3.6	$ 3.3
Accretion of deemed dividends on Series A Preferred Stock	7.9	7.0
Impact of accounting standard adoption recorded in retained earnings	—	5.2
Non-cash balance sheet movements related to acquisition of related party:		
Noncontrolling interest	$ —	$ 1.2
Lease liabilities arising from recognition of right-of-use assets:		
Operating lease	$ 0.4	$ —
Finance lease	1.5	—

(1) Interest capitalized on major projects was $18.9 million and $9.6 million for the three months ended March 31, 2019 and 2018.

Note 21 — Segment Information

We operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business). Our 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 (including the Midland and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) and South Central Kansas; the Williston Basin in North Dakota; and 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 the Grand Prix pipeline, which is currently under construction with certain segments of the pipeline currently in operation. 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 March 31, 2019				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 247.6	$ 1,726.8	$ 2.1	$ —	$ 1,976.5
Fees from midstream services	199.9	123.0	—	—	322.9
	447.5	1,849.8	2.1	—	2,299.4
Intersegment revenues					
Sales of commodities	822.8	38.4	—	(861.2)	—
Fees from midstream services	1.9	5.5	—	(7.4)	—
	824.7	43.9	—	(868.6)	—
Revenues	$ 1,272.2	$ 1,893.7	$ 2.1	$ (868.6)	$ 2,299.4
Operating margin	$ 229.0	$ 152.1	$ 2.1	$ —	$ 383.2
Other financial information:					
Total assets (1)	$ 11,713.9	$ 5,644.9	$ 87.9	$ 122.5	$ 17,569.2
Goodwill	$ 46.6	$ —	$ —	$ —	$ 46.6
Capital expenditures	$ 417.8	$ 470.9	$ —	$ 16.9	$ 905.6

(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 March 31, 2018				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 265.2	$ 1,926.3	$ (17.8)	$ —	$ 2,173.7
Fees from midstream services	161.3	120.6	—	—	281.9
	426.5	2,046.9	(17.8)	—	2,455.6
Intersegment revenues					
Sales of commodities	866.5	55.7	—	(922.2)	—
Fees from midstream services	1.9	6.9	—	(8.8)	—
	868.4	62.6	—	(931.0)	—
Revenues	$ 1,294.9	$ 2,109.5	$ (17.8)	$ (931.0)	$ 2,455.6
Operating margin	$ 220.8	$ 138.4	$ (17.8)	$ —	$ 341.4
Other financial information:					
Total assets (1)	$ 10,908.5	$ 3,595.1	$ 103.0	$ 146.6	$ 14,753.2
Goodwill	$ 256.6	$ —	$ —	$ —	$ 256.6
Capital expenditures	$ 273.2	$ 251.0	$ —	$ 33.8	$ 558.0

(1) Assets 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 March 31,	
	2019	2018
Sales of commodities:		
Revenue recognized from contracts with customers:		
Natural gas	$ 411.3	$ 470.1
NGL	1,408.1	1,607.3
Condensate and crude oil	137.7	86.9
Petroleum products	7.6	48.2
	1,964.7	2,212.5
Non-customer revenue:		
Derivative activities - Hedge	21.3	(28.0)
Derivative activities - Non-hedge (1)	(9.5)	(10.8)
	11.8	(38.8)
Total sales of commodities	1,976.5	2,173.7
Fees from midstream services:		
Revenue recognized from contracts with customers:		
NGL transportation and services	36.2	41.1
Storage, terminaling and export	79.6	78.2
Gathering and processing	194.5	152.1
Other	12.6	10.5
Total fees from midstream services	322.9	281.9
Total revenues	$ 2,299.4	$ 2,455.6

(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 March 31, 2019	Three Months Ended March 31, 2018
Reconciliation of reportable segment operating margin to income (loss) before income taxes:		
Gathering and Processing operating margin	$ 229.0	$ 220.8
Logistics and Marketing operating margin	152.1	138.4
Other operating margin	2.1	(17.8)
Depreciation and amortization expense	(237.4)	(198.1)
General and administrative expense	(81.1)	(56.7)
Interest income (expense), net	(80.6)	16.1
Change in contingent considerations	(9.7)	(56.1)
Other, net	(2.0)	1.2
Income (loss) before income taxes	$ (27.6)	$ 47.8

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, 2018 ("Annual Report"), as well as the unaudited consolidated financial statements and notes hereto included in this Quarterly Report on Form 10-Q.

Overview

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

Our Operations

We are engaged primarily in the business of:

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

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 (including the Midland and Delaware Basins); the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) 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 also includes the Grand Prix pipeline ("Grand Prix"), as well as our equity interest in Gulf Coast Express Pipeline LLC ("GCX"), which are both currently under construction and expected to fully begin operations in 2019. Grand Prix, once fully completed, will integrate our gathering and processing positions in the Permian Basin, Southern Oklahoma and North Texas with our downstream facilities in Mont Belvieu, Texas. 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 February 2018, in response to increasing production and to meet the infrastructure needs of producers, 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, began operations at the end of April 2019. The second plant, known as the Pembrook Plant, is expected to begin operations early in the third quarter of 2019.

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. The agreements are underpinned by the customer's dedication of significant acreage within a large, well-defined area in the Delaware Basin. We are completing construction of approximately 220 miles of 12- to 24-inch high-pressure rich gas gathering pipelines across the Delaware Basin. We are also constructing 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. We have also commenced construction of a second 250 MMcf/d cryogenic natural gas processing plant (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 expected to be approximately $500 million.

Badlands

In January 2018, we announced the formation of a 50/50 joint venture with Hess Midstream Partners LP under which Targa will construct and operate a new 200 MMcf/d natural gas processing plant (“Little Missouri 4”) at Targa’s existing Little Missouri facility. Little Missouri 4 is anticipated to be completed early in the third quarter of 2019.

Downstream Segment Expansion

Grand Prix NGL Pipeline

In May 2017, we announced initial plans to construct a new common carrier NGL pipeline in Texas and New Mexico, which is owned by Grand Prix Pipeline LLC (“Grand Prix Joint Venture”), a consolidated subsidiary of which Targa owns a 56% interest. Since then, we announced an extension to Southern Oklahoma in March 2018 and an extension to Central Oklahoma in February 2019. Each announced extension is 100% owned by Targa.

Grand Prix will transport NGLs from the Permian Basin, North Texas, Southern Oklahoma, and Central Oklahoma to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. The pipeline is comprised of four primary segments:

- Permian Basin Segment – Connects our Gathering and Processing positions throughout the Delaware and Midland Basins to North Texas. The capacity of the 24-inch diameter pipeline segment from the Permian Basin is approximately 300 MBbl/d, expandable to 550 MBbl/d. The Permian Basin Segment is owned by the Grand Prix Joint Venture. This segment began receiving NGLs in the first quarter of 2019 and is now transporting NGLs to North Texas and delivering to third party pipelines.

- Southern Oklahoma Extension – Connects our SouthOK and North Texas Gathering and Processing positions to the North Texas to Mont Belvieu Segment. The extension is owned solely by Targa and will vary in capacity based on telescoping pipe size.

- North Texas to Mont Belvieu Segment – The Permian Basin Segment and Southern Oklahoma Extension connect to a 30-inch diameter pipeline segment in North Texas, which will connect Permian, North Texas and Oklahoma volumes to Mont Belvieu. The North Texas to Mont Belvieu Segment will have a capacity of approximately 450 MBbl/d, expandable to 950 MBbl/d, and is owned by the Grand Prix Joint Venture.

The three segments noted above are expected to be fully in service in the third quarter of 2019.

- Central Oklahoma Extension – Extends from Southern Oklahoma to the STACK region of Central Oklahoma where it will connect with The Williams Companies, Inc. (“Williams”) Bluestem Pipeline, linking the Conway, Kansas, and Mont Belvieu, Texas, NGL markets. In connection with this project, Williams has committed significant volumes to us that we will transport on Grand Prix and fractionate at our Mont Belvieu facilities. Williams also had an initial option to purchase a 20% equity interest in one of our recently announced fractionation trains (Train 7 or Train 8) in Mont Belvieu. Williams exercised its option to acquire a 20% equity interest in Train 7 and subsequently executed a joint venture agreement with us in the second quarter of 2019. See further discussion below. The Central Oklahoma Extension is owned solely by Targa and is expected to be completed in the first quarter of 2021.

Grand Prix volumes flowing on the pipeline from the Permian Basin to Mont Belvieu are included in the Grand Prix Joint Venture, while the volumes flowing from North Texas and Oklahoma to Mont Belvieu accrue solely to Targa's benefit. Total growth capital spending on Grand Prix, including the extensions into Oklahoma, is estimated to be approximately $1.9 billion, with our portion of growth capital spending estimated to be approximately $1.3 billion.

Fractionation Expansion

In February 2018, we announced plans to construct a new 100 MBbl/d fractionation train in Mont Belvieu, Texas ("Train 6"), which began operations in early May 2019. The total cost of the fractionation train and related infrastructure is expected to be approximately $350 million. Targa Train 6 LLC, a joint venture between Targa and Stonepeak Infrastructure Partners ("Stonepeak"), owns 100% interest in certain assets associated with Train 6. Certain fractionation-related infrastructure for Train 6, such as storage caverns and brine handling, will be funded and owned 100% by Targa.

In November 2018, we announced plans to construct two new 110 MBbl/d fractionation trains in Mont Belvieu, Texas ("Train 7 and Train 8"), which are expected to begin operations in the first quarter of 2020 and third quarter of 2020, respectively. The total cost of these fractionation trains and related infrastructure is expected to be approximately $825 million. In connection with the Central Oklahoma Extension, Williams exercised its option to acquire a 20% equity interest in Train 7 and executed a joint venture agreement with us. Certain fractionation-related infrastructure for Train 7, including storage caverns and brine handling, will be funded and owned 100% by Targa.

LPG Export Expansion

In February 2019, we announced plans to further expand our LPG export capabilities of propane and butanes at our Galena Park Marine Terminal by increasing refrigeration capacity and associated load rates. Our current effective export capacity of 7 MMBbl per month will increase to approximately 11 to 15 MMBbl per month, depending upon the mix of propane and butane demand, vessel size and availability of supply, among other factors. The total cost of the expansion and related infrastructure is expected to be approximately $120 million and is expected to be completed in the third quarter of 2020.

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 Pipeline"), a natural gas pipeline from the Waha hub, including direct connections to the tailgate of many of our Midland Basin processing facilities, to Agua Dulce in South Texas. The pipeline will provide an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. Targa GCX Pipeline LLC, a joint venture between us and Stonepeak, and DCP each own a 25% interest, KMTP owns a 35% interest, and Altus Midstream Company owns the remaining 15% interest in GCX. KMTP serves as the construction manager and operator of GCX Pipeline. We have committed significant volumes to GCX Pipeline. In addition, Pioneer Natural Resources Company, a joint owner in our WestTX Permian Basin assets, has committed volumes to the project. GCX Pipeline 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 Pipeline is expected to be in service in the fourth quarter of 2019.

Channelview Splitter

The Channelview Splitter, located at our Channelview Terminal on the Houston Ship Channel, is currently operating but still being tested by engineering and operations and has an estimated total cost of approximately $160 million. 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, distillate, gas oil, kerosene/jet fuel and liquefied petroleum gas and will provide segregated storage for the crude and condensate and each of their components. We are working on commercialization of the Channelview Splitter.

Badlands Interest Sale

In April 2019, we closed on the sale of a 45% interest in Targa Badlands LLC, the entity that holds substantially all of our assets in North Dakota, to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities (collectively, "Blackstone") for $1.6 billion in cash. We used the net cash proceeds to repay debt and for general corporate purposes, including funding our growth capital program. We continue to be the operator of Targa Badlands LLC and hold majority governance rights. Future growth capital of Targa Badlands LLC is expected to be funded on a pro rata ownership basis. Targa Badlands LLC will pay a minimum quarterly distribution ("MQD") to Blackstone and Targa, with Blackstone having a priority right on such MQDs. Additionally, Blackstone's capital contributions would have a liquidation preference upon a sale of Targa Badlands LLC.

Financing Activities

In January 2019, the Partnership issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6⅞% Senior Notes due January 2029, resulting in total net proceeds of $1,487.3 million. The net proceeds from the offerings were used to redeem in full the Partnership's 4⅛% Senior Notes due 2019, at par value plus accrued interest through the redemption date, with the remainder used for general partnership purposes, which included repaying borrowings under the Partnership's credit facilities.

Corporation Tax Matters

The Internal Revenue Service ("IRS") notified us on April 3, 2019, that it will examine Targa's federal income tax returns (Form 1120) for 2014, 2015 and 2016. We are fully cooperating with the IRS in the audit process and do not anticipate material changes in prior year taxable income.

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 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 such as available commodity throughput 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 Grand Prix, 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 may increase with system expansions and will 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 less producer payments and other natural gas and crude oil purchases; and
- service fees related to natural gas and crude oil gathering, treating and processing.

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 (loss) attributable to TRC. 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 March 31,	
	2019	2018
	(In millions)	
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin		
Net income (loss) attributable to TRC	$ (38.9)	$ 22.9
Net income (loss) attributable to noncontrolling interests	14.2	16.0
Net income (loss)	(24.7)	38.9
Depreciation and amortization expense	237.4	198.1
General and administrative expense	81.1	56.7
Interest (income) expense, net	80.6	(16.1)
Income tax expense (benefit)	(2.9)	8.9
(Gain) loss on sale or disposition of assets	3.2	(0.1)
(Gain) loss from financing activities	1.4	—
Change in contingent considerations	9.7	56.1
Other, net	(2.6)	(1.1)
Operating margin	**383.2**	**341.4**
Operating expenses	190.2	173.2
Gross margin	**$ 573.4**	**$ 514.6**

	Three Months Ended March 31,	
	2019	2018
	(In millions)	
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow		
Net income (loss) attributable to TRC	$ (38.9)	$ 22.9
Income attributable to TRP preferred limited partners	2.8	2.8
Interest (income) expense, net (1)	80.6	(16.1)
Income tax expense (benefit)	(2.9)	8.9
Depreciation and amortization expense	237.4	198.1
(Gain) loss on sale or disposition of assets	3.2	(0.1)
(Gain) loss from financing activities (2)	1.4	—
Equity (earnings) loss	(2.8)	(1.5)
Distributions from unconsolidated affiliates and preferred partner interests, net	6.8	6.9
Change in contingent considerations	9.7	56.1
Compensation on equity grants	16.5	13.2
Splitter Agreement (3)	—	10.8
Risk management activities	7.2	9.7
Noncontrolling interests adjustments (4)	(7.1)	(5.1)
TRC Adjusted EBITDA	**$ 313.9**	**$ 306.6**
Distributions to TRP preferred limited partners	(2.8)	(2.8)
Splitter Agreement (3)	—	(10.8)
Interest expense on debt obligations (5)	(80.0)	(54.8)
Maintenance capital expenditures	(35.6)	(22.3)
Noncontrolling interests adjustments of maintenance capital expenditures	1.2	0.5
Distributable Cash Flow	**$ 196.7**	**$ 216.4**

(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. As a result of Vitol Americas Corp.'s election to terminate the Splitter Agreement in December 2018, the full amount of the 2018 annual cash payment was recognized in Adjusted EBITDA in the fourth quarter of 2018.

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

(5) Excludes amortization of interest expense.

Consolidated Results of Operations

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	2019 vs. 2018	
	(In millions)			
Revenues				
Sales of commodities	$ 1,976.5	$ 2,173.7	$ (197.2)	(9%)
Fees from midstream services	322.9	281.9	41.0	15%
Total revenues	2,299.4	2,455.6	(156.2)	(6%)
Product purchases	1,726.0	1,941.0	(215.0)	(11%)
Gross margin (1)	573.4	514.6	58.8	11%
Operating expenses	190.2	173.2	17.0	10%
Operating margin (1)	383.2	341.4	41.8	12%
Depreciation and amortization expense	237.4	198.1	39.3	20%
General and administrative expense	81.1	56.7	24.4	43%
Other operating (income) expense	3.4	0.3	3.1	NM
Income (loss) from operations	61.3	86.3	(25.0)	(29%)
Interest income (expense), net	(80.6)	16.1	(96.7)	NM
Equity earnings (loss)	2.8	1.5	1.3	87%
Gain (loss) from financing activities	(1.4)	—	(1.4)	—
Change in contingent considerations	(9.7)	(56.1)	46.4	83%
Income tax (expense) benefit	2.9	(8.9)	11.8	133%
Net income (loss)	(24.7)	38.9	(63.6)	(163%)
Less: Net income (loss) attributable to noncontrolling interests	14.2	16.0	(1.8)	(11%)
Net income (loss) attributable to Targa Resources Corp.	(38.9)	22.9	(61.8)	(270%)
Dividends on Series A Preferred Stock	22.9	22.9	—	—
Deemed dividends on Series A Preferred Stock	7.9	7.0	0.9	13%
Net income (loss) attributable to common shareholders	$ (69.7)	$ (7.0)	$ (62.7)	NM
Financial data:				
Adjusted EBITDA (1)	$ 313.9	$ 306.6	$ 7.3	2%
Distributable cash flow (1)	196.7	216.4	(19.7)	(9%)
Growth capital expenditures (2)	870.0	535.6	334.4	62%
Maintenance capital expenditures (3)	35.6	22.4	13.2	59%

(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) Growth capital expenditures, net of contributions from noncontrolling interest, were $752.5 million and $446.8 million for the three months ended March 31, 2019 and 2018. Net contributions to investments in unconsolidated affiliates were $29.1 million and $32.4 million for the three months ended March 31, 2019 and 2018.

(3) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $34.4 million and $21.9 million for the three months ended March 31, 2019 and 2018.

NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018

The decrease in commodity sales reflects lower NGL, natural gas and condensate prices ($437.8 million) and lower petroleum volumes due to the sale of certain petroleum logistics storage and terminaling facilities in the fourth quarter of 2018 ($40.5 million), partially offset by higher NGL and crude marketing volumes ($228.4 million) and the impact of hedges ($50.5 million). The increase in fee-based revenue was primarily due to higher gas processing and crude gathering fees.

The decrease in product purchases reflects decreased NGL, natural gas and condensate prices, partially offset by increases in volumes.

The higher operating margin and gross margin in 2019 reflect increased segment margin results for Gathering and Processing and Logistics and Marketing. 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 primarily due to higher depreciation related to major growth projects placed in service, including the Permian Basin Segment of Grand Prix, and additional processing plants and associated infrastructure in the Permian Basin. The increase is partially offset by lower depreciation for our downstream facilities, resulting from the sale of certain petroleum logistics storage and terminaling facilities in the fourth quarter of 2018.

General and administrative expense increased primarily due to higher compensation and benefits, including increased staffing levels, system costs and outside professional services.

Interest expense, net, increased due to a reduction of non-cash interest income related to the mandatorily redeemable interests, and higher average borrowings, partially offset by higher capitalized interest related to our major growth investments. During 2018, we recognized non-cash interest income resulting from a decrease in the estimated redemption value of the mandatorily redeemable interests, primarily attributable to the February 2018 amendments to such arrangements.

During 2019, we recorded expense of $9.7 million resulting from an increase in the value of the Permian Acquisition contingent consideration liability. The increase in 2019 was primarily attributable to the elimination of discounting and an increase in actual gross margin through the end of the earn-out period. During 2018, we recorded expense of $56.1 million resulting primarily from the increase in fair value as of March 31, 2018 of the Permian Acquisition contingent consideration liability. The fair value change was primarily related to an increase in underlying forecasted volumes for the remainder of the earn-out period and a shorter term over which such projections are discounted.

During 2019 we recorded an income tax benefit, whereas in 2018 we recorded income tax expense. The change was primarily due to lower net income (loss) before tax, a lower annual effective tax rate and higher tax benefits related to share-based payment awards that vested during the quarter.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	Consolidated Operating Margin
	(In millions)			
Three Months Ended:				
March 31, 2019	$ 229.0	$ 152.1	$ 2.1	$ 383.2
March 31, 2018	220.8	138.4	(17.8)	341.4

Gathering and Processing Segment

	Three Months Ended March 31,		2019 vs. 2018	
	2019	2018		
	(In millions, except operating statistics and price amounts)			
Gross margin	$ 351.9	$ 325.6	$ 26.3	8%
Operating expenses	122.9	104.8	18.1	17%
Operating margin	$ 229.0	$ 220.8	$ 8.2	4%
Operating statistics (1):				
Plant natural gas inlet, MMcf/d (2),(3)				
Permian Midland (4)	1,334.4	1,014.1	320.3	32%
Permian Delaware	480.4	409.2	71.2	17%
Total Permian	1,814.8	1,423.3	391.5	
SouthTX (5)	363.9	416.3	(52.4)	(13%)
North Texas	230.5	235.1	(4.6)	(2%)
SouthOK (6)	620.0	529.9	90.1	17%
WestOK	338.1	350.1	(12.0)	(3%)
Total Central	1,552.5	1,531.4	21.1	
Badlands (7)	96.9	73.3	23.6	32%
Total Field	3,464.2	3,028.0	436.2	
Coastal	769.9	724.3	45.6	6%
Total	4,234.1	3,752.3	481.8	13%
NGL production, MBbl/d (3)				
Permian Midland (4)	184.3	140.2	44.1	31%
Permian Delaware	60.5	45.7	14.8	32%
Total Permian	244.8	185.9	58.9	
SouthTX (5)	48.8	54.1	(5.3)	(10%)
North Texas	26.8	25.9	0.9	3%
SouthOK (6)	58.3	48.9	9.4	19%
WestOK	24.1	19.4	4.7	24%
Total Central	158.0	148.3	9.7	
Badlands	11.4	10.2	1.2	12%
Total Field	414.2	344.4	69.8	
Coastal	48.4	42.6	5.8	14%
Total	462.6	387.0	75.6	20%
Crude oil gathered, Badlands, MBbl/d	169.5	117.7	51.8	44%
Crude oil gathered, Permian, MBbl/d	67.4	49.4	18.0	36%
Natural gas sales, BBtu/d (3)	1,925.9	1,767.3	158.6	9%
NGL sales, MBbl/d	359.5	300.4	59.1	20%
Condensate sales, MBbl/d	12.5	16.2	(3.7)	(23%)
Average realized prices (8):				
Natural gas, $/MMBtu	1.89	2.37	(0.48)	(20%)
NGL, $/gal	0.45	0.59	(0.14)	(24%)
Condensate, $/Bbl	47.09	59.66	(12.57)	(21%)

(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) Permian Midland includes operations in WestTX, of which we own 72.8%, 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, of which we own a 50% interest through the Carnero Joint Venture. SouthTX also includes the Silver Oak II Plant, of which we owned a 100% interest until it was contributed to the Carnero Joint Venture in May 2018. 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.
(8) Average realized prices exclude the impact of hedging activities presented in Other.

Three Months Ended March 31, 2019 Compared to Three Months Ended March 31, 2018

The increase in gross margin was primarily due to higher Badlands and Permian volumes, partially offset by lower commodity prices and lower SouthTX volumes. The effect of commodity prices excludes the impact of hedging activities presented in Other. 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. Total crude oil gathered volumes increased in the Permian region due to production from new wells. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to 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 regions were relatively flat.

Logistics and Marketing Segment

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	2019 vs. 2018	
	(In millions, except operating statistics and price amounts)			
Gross margin	$ 219.5	$ 206.9	$ 12.6	6%
Operating expenses	67.4	68.5	(1.1)	(2%)
Operating margin	$ 152.1	$ 138.4	$ 13.7	10%
Operating statistics MBbl/d (1):				
Fractionation volumes (2)	456.6	389.7	66.9	17%
Export volumes (3)	213.1	201.9	11.2	6%
NGL sales	586.2	514.8	71.4	14%
Average realized prices:				
NGL realized price, $/gal	$ 0.60	$ 0.76	$ (0.16)	(21%)

(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 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. Fractionation volumes for 2019 reflect volumes delivered and fractionated, whereas fractionation volumes for 2018 reflect volumes delivered and settled under fractionation contracts.

(3) 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 March 31, 2019 Compared to Three Months Ended March 31, 2018

Logistics and Marketing gross margin increased due to higher LPG export margin, higher fractionation margin, partially offset by lower terminaling and storage throughput, and lower commercial transportation margin. LPG export margin increased primarily due to higher volumes despite restrictions and temporary closures of the Houston Ship Channel during the quarter. 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). Terminaling and storage throughput decreased due to the sale of certain petroleum logistics storage and terminaling facilities in the fourth quarter of 2018. Commercial transportation margin decreased due to the sale of the Company’s inland marine barge business in the second quarter of 2018.

Operating expenses decreased due to lower taxes and maintenance.

Other

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018	2019 vs. 2018
	(In millions)		
Gross margin	$ 2.1	$ (17.8)	$ 19.9
Operating margin	$ 2.1	$ (17.8)	$ 19.9

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 March 31, 2019			Three Months Ended March 31, 2018		
	(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)	12.1	$ 0.72	$ 8.7	17.4	$ 0.33	$ 5.8
NGL (MMgal)	69.4	0.01	0.5	87.2	(0.11)	(9.4)
Crude oil (MBbl)	0.3	(0.04)	—	0.4	(10.30)	(4.6)
Non-hedge accounting (2)			(7.1)			(9.6)
			$ 2.1			$ (17.8)

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.
(2) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.

Our Liquidity and Capital Resources

As of March 31, 2019, we had $124.9 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 depends 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. If the Partnership cannot make distributions to us, we may be limited in our ability, or unable, to pay dividends on our common stock. In addition, so long as any shares of our Preferred Shares are outstanding, certain common stock distribution limitations exist.

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 supplement these sources of liquidity with joint venture arrangements and proceeds from asset sales. 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 May 3, 2019, was:

	May 3, 2019 (In millions) TRC	TRP	Consolidated Total
Cash on hand	$ 13.5	$ 297.9	$ 311.4
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	—	334.9	334.9
	683.5	2,832.8	3,516.3
Less: Outstanding borrowings under the TRC Revolver	—	—	—
Outstanding borrowings under the TRP Revolver	—	—	—
Outstanding borrowings under the Securitization Facility	—	(300.0)	(300.0)
Outstanding letters of credit under the TRP Revolver	—	(66.0)	(66.0)
Total liquidity	$ 683.5	$ 2,466.8	$ 3,150.3

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 payables and accruals related to major growth projects; (iv) changes in the fair value of the current portion of derivative contracts; (v) monthly swings in borrowings under the Securitization Facility; and (vi) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

Working capital as of March 31, 2019 increased $519.3 million compared to December 31, 2018. The increase was primarily attributable to the February redemption of our 4⅛% Senior Notes due 2019, partially offset by a lower cash balance and a decrease in our net risk management asset position due to changes in forward prices of commodities.

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 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 development joint ventures (“DevCo JVs”) with investment vehicles affiliated with Stonepeak, which committed a maximum of approximately $960 million of capital to the DevCo JVs.

As of March 31, 2019, total contributions from Stonepeak to the DevCo JVs were $701.3 million. As of March 31, 2019, total contributions from Blackstone to the Grand Prix Joint Venture were $265.0 million. These contributions from Stonepeak and Blackstone are included in noncontrolling interests.

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 March 31, 2019 and December 31, 2018, the aggregate principal amount outstanding of our senior notes and other various long-term debt obligations, including unamortized premiums, debt issuance costs and non-current liabilities of finance leases, was $7,118.5 million and $5,632.4 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 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 March 31, 2019, we did not have any interest rate hedges.

In January 2019, the Partnership issued $750.0 million of 6½% Senior Notes due July 2027 and $750.0 million of 6⅞% Senior Notes due January 2029, resulting in total net proceeds of $1,487.3 million. The net proceeds from the offerings were used to redeem in full the Partnership's outstanding 4⅛% Senior Notes due 2019 at par value plus accrued interest through the redemption date and the remainder was used for general partnership purposes, which included repaying borrowings under the Partnership's credit facilities.

In April 2019, we closed on the sale of a 45% interest in Targa Badlands LLC, the entity that holds substantially all of our assets in North Dakota, to funds managed by Blackstone for $1.6 billion in cash. We used the net cash proceeds to repay debt and for general corporate purposes, including funding our growth capital program. We continue to be the operator of Targa Badlands LLC and hold majority governance rights. Future growth capital of Targa Badlands LLC is expected to be funded on a pro rata ownership basis. Targa Badlands LLC will pay an MQD to Blackstone and Targa, with Blackstone having a priority right on such MQDs. Additionally, Blackstone's capital contributions would have a liquidation preference upon a sale of Targa Badlands LLC.

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 March 31, 2019, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

Three Months Ended March 31,		
2019	**2018**	**2019 vs. 2018**
	(In millions)	
$ 307.6	$ 354.4	$ (46.8)

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 purchase of NGLs and natural gas, (iii) changes in payables and accruals related to major growth projects, and (iv) 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 decreased in 2019 compared to 2018, primarily due to the increase in payments for operating and general and administrative expenses resulting from system expansions and higher compensation and benefits, and increases in interest payments due to higher average borrowings, partially offset by the impact of lower commodity prices and increased margin withdrawals related to our derivative contracts. Lower commodity prices resulted in lower product purchases, partially offset by lower cash collections from customers.

Cash Flows Used in Investing Activities

Three Months Ended March 31,		
2019	2018	2019 vs. 2018
	(In millions)	
$ (1,069.2)	$ (677.3)	$ (391.9)

Cash used in investing activities increased in 2019 compared to 2018, primarily due to higher outlays for property, plant and equipment of $347.4 million, mainly related to the construction of Train 7 and Train 8, and additional processing plants and associated infrastructure in the Permian Basin. The change is also attributable to a $29.4 million increase in our contributions to unconsolidated affiliates essentially due to higher construction activities of GCX Pipeline, partially offset by lower construction activities of Little Missouri 4.

Cash Flows from Financing Activities

	Three Months Ended March 31,	
	2019	2018
Source of Financing Activities, net	(In millions)	
Debt, including financing costs	$ 732.7	$ 310.0
Contributions from noncontrolling interests	196.8	280.1
Equity offerings, net of financing costs	—	57.7
Dividends and distributions	(246.9)	(225.4)
Other	(28.2)	(16.9)
Net cash provided by financing activities	$ 654.4	$ 405.5

In 2019, we realized a net source of cash from financing activities primarily due to a net increase of debt outstanding, contributions from noncontrolling interests, partially offset by payments of dividends and distributions. The issuance of 6½% Senior Notes due 2027 and 6⅞% Senior Notes due January 2029, partially offset by the redemption of 4⅛% Senior Notes due November 2019 contributed to the net increase of debt outstanding. The contributions from noncontrolling interests were primarily from Stonepeak and Blackstone to fund growth projects.

In 2018, we realized a net source of cash from financing activities primarily due to borrowings under the TRP Revolver and contributions from noncontrolling interests, partially offset by the payments of dividends and distributions. The contributions from noncontrolling interests were primarily from Stonepeak and Blackstone to fund growth projects.

Common Dividends

The following table details the dividends on common stock declared and/or paid by us for the three months ended March 31, 2019:

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)			
March 31, 2019	May 15, 2019	$ 215.2	$ 211.5	$ 3.7	$ 0.91000
December 31, 2018	February 15, 2019	215.2	211.2	4.0	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 $22.9 million were paid to holders of the Series A Preferred during the three months ended March 31, 2019. As of March 31, 2019, cash dividends accrued for our Series A Preferred were $22.9 million, which will be paid on May 14, 2019.

Capital Expenditures

Our capital expenditures 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.

The following table details cash outlays for capital projects for the three months ended March 31, 2019 and 2018:

	Three Months Ended March 31,	
	2019	2018
	(In millions)	
Capital expenditures:		
Growth (1)	$ 870.0	$ 535.6
Maintenance (2)	35.6	22.4
Gross capital expenditures	905.6	558.0
Transfers of capital expenditures to investment in unconsolidated affiliates	—	16.0
Transfers from materials and supplies inventory to property, plant and equipment	(1.1)	(0.4)
Change in capital project payables and accruals	38.8	22.3
Cash outlays for capital projects	$ 943.3	$ 595.9

(1) Growth capital expenditures, net of contributions from noncontrolling interests, were $752.5 million and $446.8 million for the three months ended March 31, 2019 and 2018. Net contributions to investments in unconsolidated affiliates were $29.1 million and $32.4 million for the three months ended March 31, 2019 and 2018.

(2) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $34.4 million and $21.9 million for the three months ended March 31, 2019 and 2018.

We currently estimate that in 2019 we will invest approximately $2,300 million in net growth capital expenditures (exclusive of outlays for business acquisitions) and net contributions to investments in unconsolidated affiliates for announced projects. Future growth capital expenditures may vary significantly based on investment opportunities. We expect that 2019 net maintenance capital expenditures will be approximately $130 million.

Total growth capital expenditures increased for the three months ended March 31, 2019 as compared to the three months ended March 31, 2018, primarily due to spending related to construction of Train 7 and Train 8, and additional processing plants and associated infrastructure in the Permian Basin. Total maintenance capital expenditures increased for the three months ended March 31, 2019 as compared to the three months ended March 31, 2018, primarily due to our increased asset base and additional infrastructure.

Off-Balance Sheet Arrangements

As of March 31, 2019, there were $56.5 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 energy 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, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk through 2023. 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 March 31, 2019, 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, (ii) future commodity purchases and sales in our Logistics and Marketing segment and (iii) natural gas transportation basis risk 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 fair value of our natural gas and NGL hedges 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.

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).

To analyze the risk associated with our derivative instruments, we utilize a sensitivity analysis. The sensitivity analysis measures the change in fair value of our derivative instruments based on a hypothetical 10% change in the underlying commodity prices, but does not reflect the impact that the same hypothetical price movement would have on the related hedged items. The financial statement impact on the fair value of a derivative instrument resulting from a change in commodity price would normally be offset by a corresponding gain or loss on the hedged item under hedge accounting. The fair values of our derivative instruments are also influenced by changes in market volatility for option contracts and the discount rates used to determine the present values.

The following table shows the effect of hypothetical price movements on the estimated fair value of our derivative instruments as of March 31, 2019:

	Fair Value	Result of 10% Price Decrease	Result of 10% Price Increase
Natural gas	$ 27.7	$ 57.3	$ (1.8)
NGLs	23.2	59.4	(12.9)
Crude oil	(4.6)	12.5	(25.4)
Total	$ 46.3	$ 129.2	$ (40.1)

The table above contains all derivative instruments outstanding as of the stated date for the purpose of hedging commodity price risk, which we are exposed to due to our equity volumes and future commodity purchases and sales, as well as basis differentials related to our gas transportation arrangements.

Our operating revenues increased (decreased) by $11.8 million and $(38.8) million during the three months ended March 31, 2019 and 2018, 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 asset position of $112.7 million at December 31, 2018 to a net asset position of $46.3 million at March 31, 2019. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position.

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 March 31, 2019, 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 March 31, 2019, the Partnership had $977.6 million in outstanding variable rate borrowings under the TRP Revolver and Securitization Facility, and we had outstanding variable rate borrowings of $435.0 million under the TRC Revolver. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact the Partnership's annual interest expense by $9.8 million and our consolidated annual interest expense by $14.1 million based on our March 31, 2019 debt balances.

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 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 $52.7 million as of March 31, 2019. The range of losses attributable to our individual counterparties as of March 31, 2019 would be between less than $0.1 million and $21.6 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 March 31, 2019, our operating income would decrease by $7.5 million in the year of the assessment.

During the three months ended March 31, 2019 and 2018, sales of commodities and fees from midstream services provided to Petredec (Europe) Limited comprised approximately 12% and 14% of our consolidated revenues.

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 March 31, 2019, 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

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
January 1, 2019 - January 31, 2019	112,231	$ 43.50	—	—
February 1, 2019 - February 28, 2019	113,534	$ 40.24	—	—
March 1, 2019 - March 31, 2019	3,892	$ 41.63	—	—

(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 January 17, 2019 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 filed January 23, 2019 (File No. 001-33303)).
4.3	Registration Rights Agreement dated as of January 17, 2019 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 filed January 23, 2019 (File No. 001-33303)).
4.4	Registration Rights Agreement dated as of January 17, 2019 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 4.3 to Targa Resources Partners LP's Current Report on Form 8-K filed January 23, 2019 (File No. 001-33303)).
10.1	Purchase Agreement dated as of January 10, 2019, 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 filed January 15, 2019 (File No. 001-33303)).
10.2+	Targa Resources Corp. 2019 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed January 22, 2019 (File No. 001-34991)).
10.3+	Form of Performance Share Unit Grant Agreement, dated as of January 17, 2019 under Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.19 to Targa Resources Corp's Annual Report on Form 10-K filed March 1, 2019 (File No. 001-34991)).

Number	Description
10.4+	Indemnification Agreement by and between Targa Resources Corp. and Julie Boushka, dated February 22, 2017 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed March 5, 2019 (File No. 001-34991)).
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
** Furnished herewith
\+ Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	Targa Resources Corp. (Registrant)
Date: May 8, 2019	By: */s/ Jennifer R. Kneale* Jennifer R. Kneale Chief Financial Officer (Principal Financial Officer)

Exhibit 31.1

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED**

I, Joe Bob Perkins, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Corp. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 8, 2019

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources Corp.
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Jennifer R. Kneale, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Targa Resources Corp. (the “registrant”);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: May 8, 2019

By: /s/ Jennifer R. Kneale
Name: Jennifer R. Kneale
Title: Chief Financial Officer of Targa Resources Corp.
(Principal Financial Officer)

Exhibit 32.1

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

In connection with the Quarterly Report on Form 10-Q of Targa Resources Corp., for the three months ended March 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Joe Bob Perkins, as Chief Executive Officer of Targa Resources Corp., hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Targa Resources Corp.

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources Corp.

Date: May 8, 2019

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

Exhibit 32.2

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

In connection with the Quarterly Report on Form 10-Q of Targa Resources Corp. for the three months ended March 31, 2019 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Jennifer R. Kneale, as Chief Financial Officer of Targa Resources Corp., hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to her knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Targa Resources Corp.

By: /s/ Jennifer R. Kneale
Name: Jennifer R. Kneale
Title: Chief Financial Officer of
Targa Resources Corp.

Date: May 8, 2019

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